CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED
FINANCIAL INFORMATION

FOR THE SIX MONTHS ENDED JUNE 30, 2019

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Q2 2019 INVESTOR FACT SHEET

CanadianUtilities.com
ELECTRICITY | PIPELINES & LIQUIDS

CANADIAN UTILITIES LIMITED
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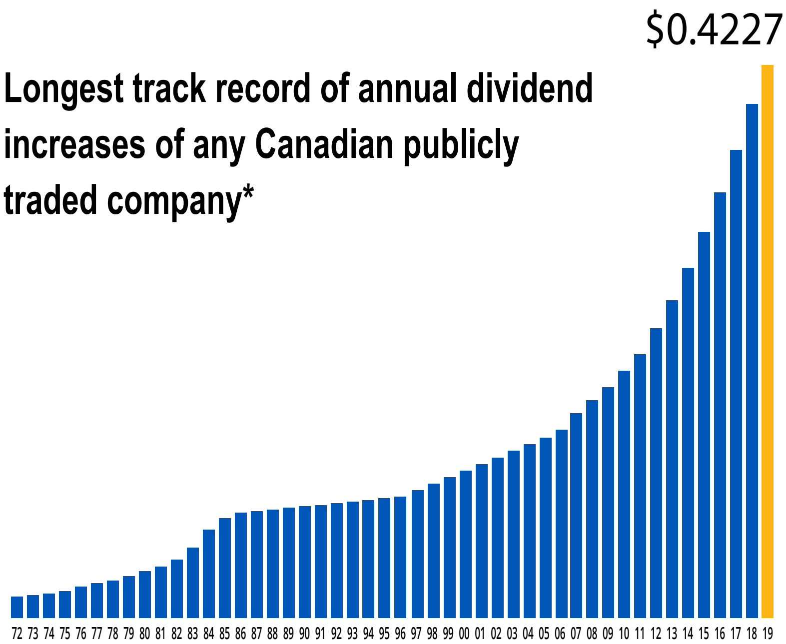
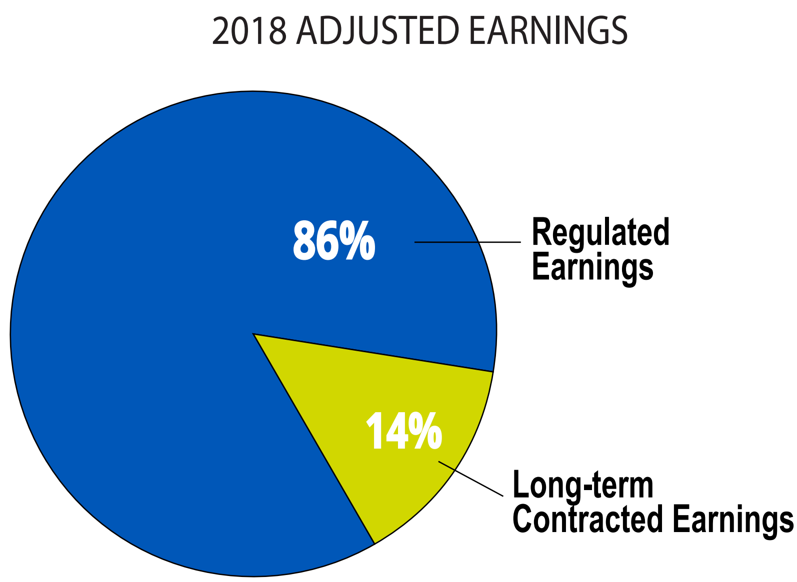
With approximately 5,000 employees and assets of $22 billion, Canadian Utilities Limited is an ATCO company. Canadian Utilities is a diversified global energy infrastructure corporation delivering service excellence and innovative business solutions in Electricity (electricity generation, transmission, and distribution); Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions); and Retail Energy (electricity and natural gas retail sales).

TRACK RECORD OF DIVIDEND GROWTH



* On July 9, 2019, Canadian Utilities declared a third quarter dividend of $0.4227 per share, or $1.69 per share annualized.

HIGH QUALITY EARNINGS BASE



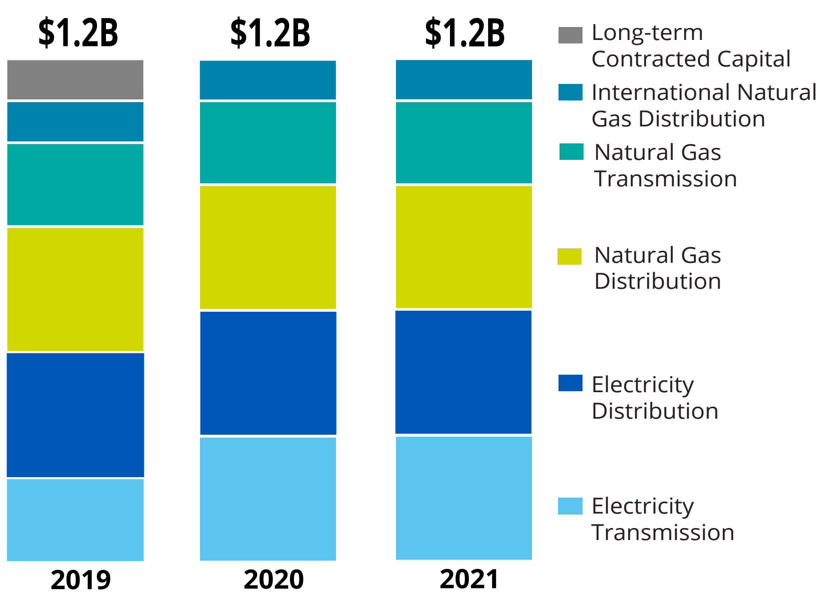
CANADIAN UTILITIES AT A GLANCE

"A-" rating by Standard & Poor's; "A" rating by DBRS Limited

Total Assets	$22 billion
Electric Powerlines	87,000 kms
Pipelines	64,500 kms
Generating Plants	21 Globally
Power Generating Capacity Share	2,517 MW *
Water Infrastructure Capacity	85,200 m³/d **
Natural Gas Storage Capacity	52 PJ ***
Hydrocarbon Storage Capacity	400,000 m³ ****

**megawatts **cubic metres per day ***petajoules ****cubic metres*

FUTURE CAPITAL INVESTMENT



$3.6 billion in Regulated Utility and contracted capital growth projects expected in 2019 - 2021

CANADIAN UTILITIES SHARE INFORMATION

Common Shares (TSX): CU, CU.X

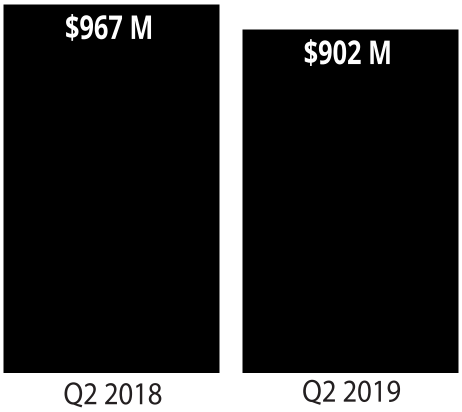
Market Capitalization	$10 billion
Weighted Average Common Shares Outstanding	272.6 million

It is important for prospective owners to understand that Canadian Utilities Limited is a diversified group of companies principally controlled by ATCO Ltd., which in turn is principally controlled by Sentgraf, a Southern family holding company. It is also important for present and prospective share owners to understand that the Canadian Utilities share registry has both Class A non-voting (CU) and Class B common (CU.X) shares.

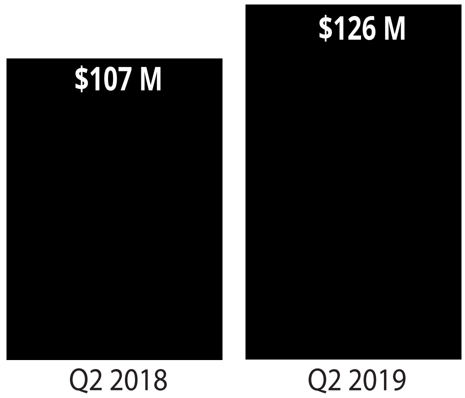
Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations. Certain statements in this document contain forward-looking information. Please refer to our forward-looking information disclaimer in Canadian Utilities' management's discussion and analysis for more information.

Q2 2019 RESULTS

CONSOLIDATED REVENUES



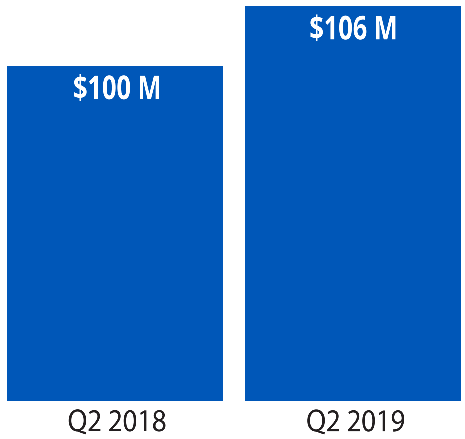
CONSOLIDATED ADJUSTED EARNINGS



ELECTRICITY

- Higher second quarter 2019 adjusted earnings were mainly due to the favourable impact of the electricity transmission 2018-2019 general tariff application (GTA) decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes, partially offset by lower availability and higher maintenance costs due to planned outages in the electricity generation business.
- In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of requested capital expenditures and operating costs as filed. The impact of this decision is an increase to second quarter 2019 adjusted earnings of $17 million.
- In May 2019, Canadian Utilities entered into definitive agreements to sell its entire Canadian fossil fuel-based electricity generation portfolio for aggregate proceeds of approximately $835 million, subject to customary closing adjustments. The sale will occur as three separate transactions. The transaction for Canadian Utilities' 50 per cent ownership interest in the 260 MW Cory Cogeneration Station closed in July 2019. The remaining two transactions, one for 10 partly- or fully-owned natural gas-fired and coal-fired electricity generation assets located in Alberta and British Columbia, and the other for Canadian Utilities' 50 per cent ownership in the 580 MW Brighton Beach Power joint venture, are expected to close in the second half of 2019.

ADJUSTED EARNINGS

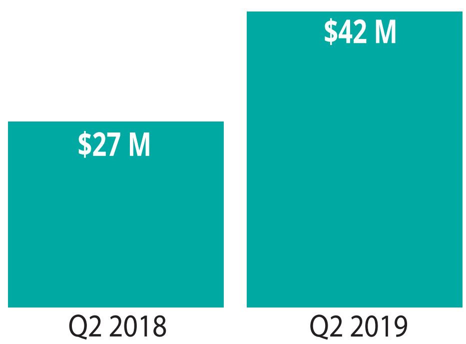


- In June 2019, Canadian Utilities, along with its partner Quanta Services Inc., entered into definitive agreements to sell Alberta PowerLine Limited Partnership (APL) for total proceeds of approximately $300 million, and the assumption of approximately $1.4 billion of APL debt. Canadian Utilities will remain as the operator of APL over its 35-year contract with the AESO. The sale is expected to close in the fourth quarter of 2019, subject to receipt of regulatory approvals and satisfaction of other customary closing conditions.

PIPELINES & LIQUIDS

- Higher second quarter 2019 adjusted earnings were mainly due to ongoing growth in the regulated rate base and the favourable impact of the natural gas transmission 2019-2020 general rate application (GRA) decision, earnings growth in the hydrocarbon storage business, cost efficiencies, and lower income taxes.
- In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The decision was received in June 2019 approving the majority of requested capital expenditures and operating costs requested as filed. The adjustments directed by the Alberta Utility Commission in the decision had a $3 million positive impact on second quarter 2019 adjusted earnings.

ADJUSTED EARNINGS



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CANADIAN UTILITIES LIMITED
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2019 SECOND QUARTER FINANCIAL INFORMATION

INVESTOR FACT SHEET

MANAGEMENT DISCUSSION AND ANALYSIS

UNAUDITED INTERIM CONSOLIDATED FINANCIAL STATEMENTS

FOR THE SIX MONTHS ENDED JUNE 30, 2019

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CANADIAN UTILITIES LIMITED
An ATCO Company

CANADIAN UTILITIES LIMITED

MANAGEMENT'S DISCUSSION AND ANALYSIS

FOR THE SIX MONTHS ENDED JUNE 30, 2019

This Management's Discussion and Analysis (MD&A) is meant to help readers understand key operational and financial events that influenced the results of Canadian Utilities Limited (Canadian Utilities, our, we, us, or the Company) during the six months ended June 30, 2019.

This MD&A was prepared as of July 24, 2019, and should be read with the Company's unaudited interim consolidated financial statements for the six months ended June 30, 2019. Additional information, including the Company's previous MD&As, Annual Information Form (2018 AIF), and audited consolidated financial statements for the year ended December 31, 2018, is available on SEDAR at www.sedar.com. Information contained in the 2018 MD&A is not discussed in this MD&A if it remains substantially unchanged.

The Company is controlled by ATCO Ltd. and its controlling share owners, Sentgraf Enterprises Ltd. and the Southern family.

Terms used throughout this MD&A are defined in the Glossary at the end of this document.

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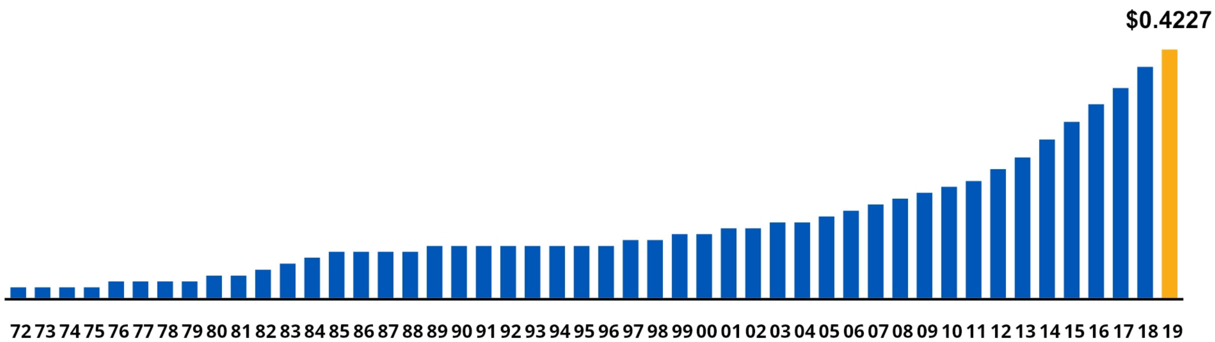
CANADIAN UTILITIES: WHAT SETS US APART

TRACK RECORD OF DIVIDEND GROWTH

We have increased our common share dividend every year for the past 47 years, the longest record of annual dividend increases of any Canadian publicly traded company. On July 9, 2019, we declared a third quarter dividend of 42.27 cents per share or $1.69 per share on an annualized basis. We aim to grow dividends in-line with our sustainable earnings growth, which is linked to growth from our regulated and long-term contracted investments.

Quarterly Dividend Rate 1972 - 2019
(dollars per share)



GROWING A HIGH QUALITY EARNINGS BASE

Over the past ten years, Canadian Utilities has invested approximately $15 billion in regulated and long-term contracted operations. The Regulated Utility portion of total adjusted earnings has grown from 46 per cent in 2009 to 86 per cent in 2018. Our highly contracted and regulated earnings base provides the foundation for continued dividend growth.

FUTURE CAPITAL INVESTMENT

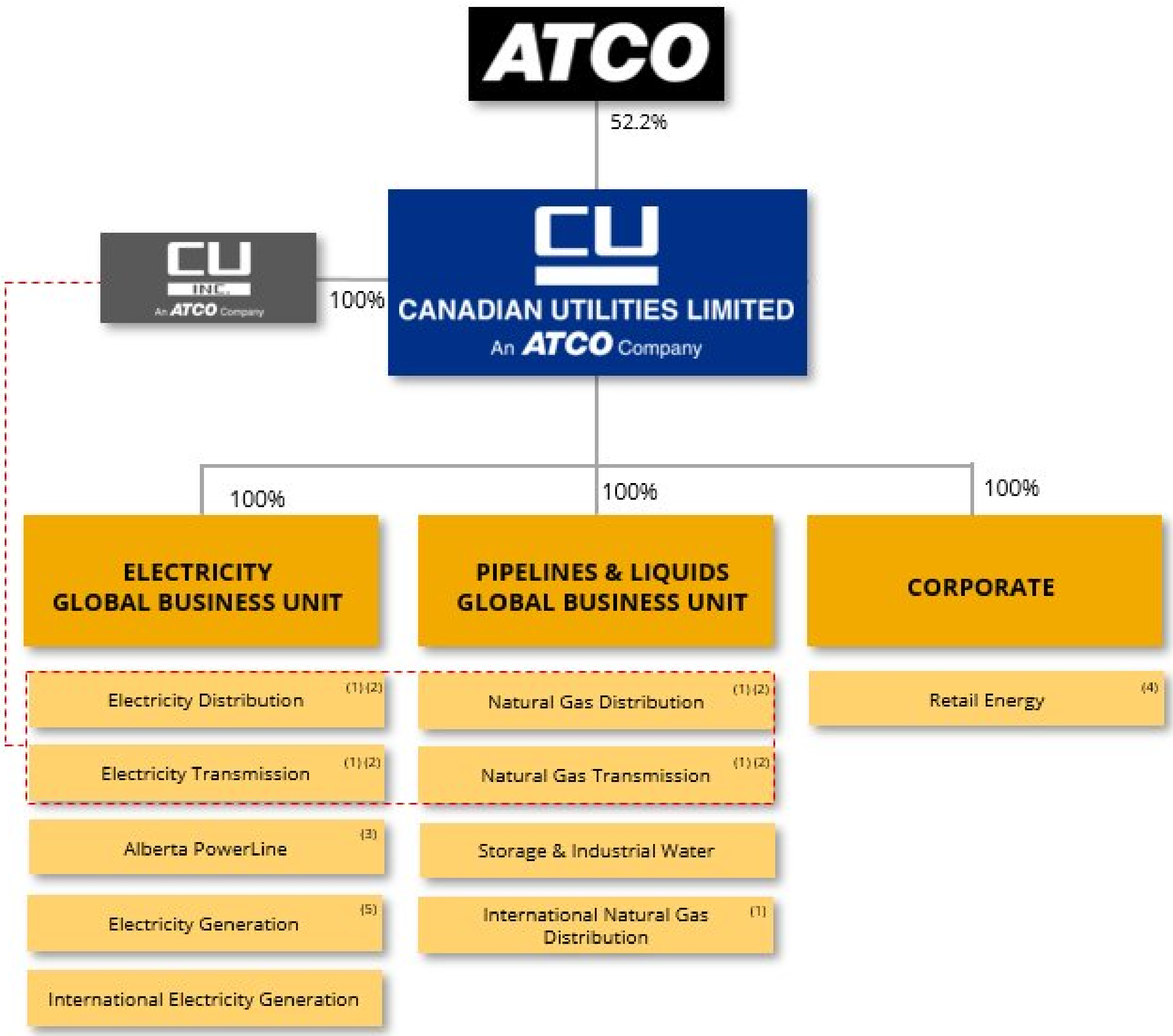
We will continue to grow our business in the years ahead. In the period 2019 to 2021, Canadian Utilities expects to invest $3.6 billion in Regulated Utility and long-term contracted assets in Canada, Australia, and Mexico, which will continue to strengthen our high quality earnings base. Of the $3.6 billion planned spend, $3.5 billion will be on Regulated Utilities.

FINANCIAL STRENGTH

Financial strength is fundamental to our current and future success. It ensures we have the financial capacity to fund our existing and future capital investment. We are committed to maintaining our strong, investment grade credit ratings, which allow us to access capital at attractive rates.

47 year	86%	$3.6B	A
track record of dividend growth	regulated earnings	3 year capital investment plans	range credit rating

ORGANIZATIONAL STRUCTURE



(1) Regulated businesses include Natural Gas Distribution, Natural Gas Transmission, International Natural Gas Distribution, Electricity Distribution, and Electricity Transmission.

(2) CU Inc. includes Natural Gas Distribution, Natural Gas Transmission, Electricity Distribution, and Electricity Transmission.

(3) Alberta PowerLine General Partner Ltd. is the general partner of Alberta PowerLine Limited Partnership (Alberta PowerLine or APL), a partnership between Canadian Utilities Limited (80 per cent) and Quanta Services, Inc. (20 per cent). In June 2019, Canadian Utilities, along with its partner Quanta Services Inc., entered into definitive agreements for the sale of Alberta Powerline Limited Partnership (APL) through a competitive process for total proceeds of approximately $300 million, and the assumption of approximately $1.4 billion of APL debt.

(4) Retail Energy, through ATCO Energy Ltd. (ATCOenergy), provides retail, commercial and industrial electricity and natural gas service in Alberta.

(5) In May 2019, Canadian Utilities entered into definitive agreements to sell its entire Canadian fossil fuel-based electricity generation portfolio for aggregate proceeds of approximately $835 million, subject to customary closing adjustments.

The unaudited interim consolidated financial statements include the accounts of Canadian Utilities Limited, and its subsidiaries, including the equity investment in joint ventures and a proportionate share of joint operations.

The unaudited interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) and the reporting currency is the Canadian dollar. Certain comparative figures throughout this MD&A have been reclassified to conform to the current presentation.

Canadian Utilities' website, www.canadianutilities.com, is a valuable source for the latest news of the Company's activities. Prior years' reports are also available on this website.

PERFORMANCE OVERVIEW

FINANCIAL METRICS

The following chart summarizes key financial metrics associated with our financial performance.

($ millions, except per share data and outstanding shares)	Three Months Ended June 30 2019	2018	Change	Six Months Ended June 30 2019	2018	Change
Key Financial Metrics						
Revenues	**902**	967	(65)	**2,091**	2,352	(261)
Adjusted earnings [1]	**126**	107	19	**326**	288	38
Electricity	**106**	100	6	**222**	197	25
Pipelines & Liquids	**42**	27	15	**140**	128	12
Corporate & Other	**(24)**	(20)	(4)	**(38)**	(37)	(1)
Intersegment Eliminations	**2**	–	2	**2**	–	2
Adjusted earnings ($ per share) [1]	**0.46**	0.39	0.07	**1.20**	1.06	0.14
Earnings (loss) attributable to equity owners of the Company	**299**	(3)	302	**516**	176	340
Earnings (loss) attributable to Class A and Class B shares	**283**	(19)	302	**483**	143	340
Earnings (loss) attributable to Class A and Class B shares ($ per share)	**1.03**	(0.07)	1.10	**1.76**	0.53	1.23
Total assets	**21,870**	20,911	959	**21,870**	20,911	959
Cash dividends declared per Class A and Class B share (cents per share)	**42.27**	39.33	2.94	**84.54**	78.66	5.88
Funds generated by operations [1]	**390**	296	94	**941**	821	120
Capital investment [1]	**241**	442	(201)	**556**	1,186	(630)
Other Financial Metrics						
Weighted average Class A and Class B shares outstanding *(thousands):*						
Basic	**272,644**	271,175	1,469	**272,619**	270,946	1,673
Diluted	**273,215**	271,818	1,397	**273,196**	271,568	1,628

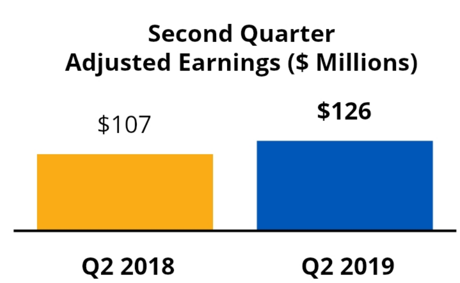
(1) Additional information regarding these measures is provided in the Non-GAAP and Additional GAAP Measures section of this MD&A.

REVENUES

Revenues for the second quarter and first half of 2019 were $902 million and $2,091 million, $65 million and $261 million lower than the same periods in 2018. Lower revenues were mainly due to reduced construction activity on Alberta PowerLine, which was completed three months ahead of schedule and on budget.

ADJUSTED EARNINGS

Our adjusted earnings for the second quarter of 2019 were $126 million, or $0.46 per share, compared to $107 million or $0.39 per share for the same period in 2018. Higher earnings were recorded in regulated electricity, Alberta PowerLine, natural gas transmission, natural gas distribution, and storage & industrial water.



The primary drivers of higher adjusted earnings results were as follows:

- Electricity adjusted earnings for the second quarter of 2019 were $6 million higher than the same period in 2018. Higher earnings were mainly due to the favourable impact of the electricity transmission 2018-2019 general tariff application (GTA) decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes partially offset by lower availability and higher maintenance costs due to planned outages in the electricity generation business. Lower income taxes are due to capital cost allowance (CCA) acceleration measures enacted by the Government of Canada in April 2019 and lower corporate income tax rates enacted by the Government of Alberta in June 2019.
- Pipelines & Liquids adjusted earnings for the second quarter of 2019 were $15 million higher than the same period in 2018. Higher earnings were mainly due to ongoing growth in the regulated rate base, the favourable impact of the natural gas transmission 2019-2020 general rates application (GRA) decision, earnings growth in the hydrocarbon storage business, cost efficiencies and lower income taxes. Lower income taxes are due to capital cost allowance (CCA) acceleration measures enacted by the Government of Canada in April 2019 and lower corporate income tax rates enacted by the Government of Alberta in June 2019.

Additional detail on the financial performance of our Global Business Units is discussed in the Global Business Unit Performance section of this MD&A.

EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the Company were $299 million for the second quarter of 2019, or $302 million higher than the same period 2018. Earnings attributable to equity owners of the Company include significant impairments, timing adjustments related to rate-regulated activities, unrealized gains or losses on mark-to-market forward commodity contracts, one-time gains and losses, and items that are not in the normal course of business or a result of day-to-day operations. These items are not included in adjusted earnings.

Earnings attributable to equity owners of the Company in the second quarter of 2019 improved due to revaluation of the deferred income tax liability mainly in the Alberta Utilities. In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022. As a result of this change, Canadian Utilities decreased income taxes and increased earnings for the three and six months ended June 30, 2019 by $203 million, all of which relates to deferred income taxes for the Alberta Utilities and are recorded as timing adjustments related to rate-regulated activities.

In the second quarter of 2019, Canadian Utilities also recorded transaction costs of $8 million for the pending sales of the Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine Limited Partnership. These costs are related to one-time transactions and are therefore excluded from adjusted earnings.

Earnings attributable to equity owners of the Company are earnings attributable to Class A and B shares plus dividends on equity preferred shares of the Company. Additional information regarding earnings attributable to Class A and B shares is presented in Note 7 of the unaudited interim consolidated financial statements.

More information on these and other items is included in the Reconciliation of Adjusted Earnings to Earnings Attributable to Equity Owners of the Company section of this MD&A.

ASSETS

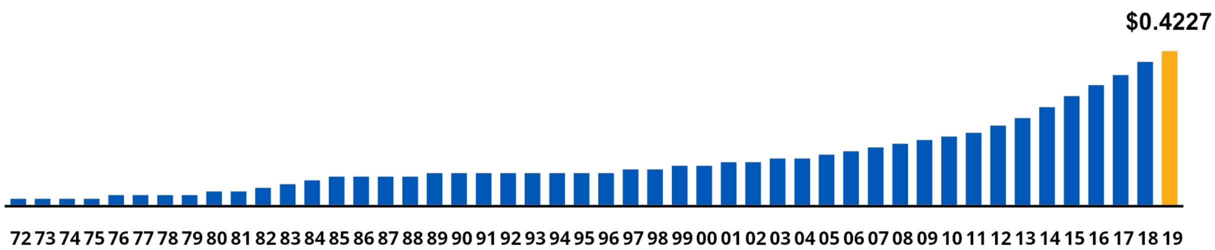
Total assets grew from $21 billion in the second quarter of 2018 to $22 billion in the second quarter of 2019. Asset growth was mainly due to continued capital investment in both APL and in the Regulated Utilities.

COMMON SHARE DIVIDENDS

On July 9, 2019, the Board of Directors declared a third quarter dividend of 42.27 cents per share. Dividends paid to Class A and Class B share owners totaled $231 million in the first half of 2019.

We have increased our common share dividend each year since 1972.

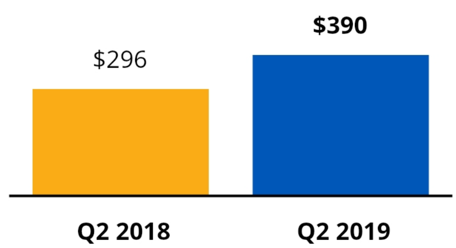
Quarterly Dividend Rate 1972 - 2019
(dollars per share)



FUNDS GENERATED BY OPERATIONS

Funds generated by operations were $390 million for the second quarter of 2019, $94 million higher than the same period in 2018. The increase was mainly due to higher earnings, the 2018 impact of a refund of customer deferral accounts in electricity transmission and a refund of over collected transmission costs in natural gas distribution.

Funds Generated By Operations
($ Millions)

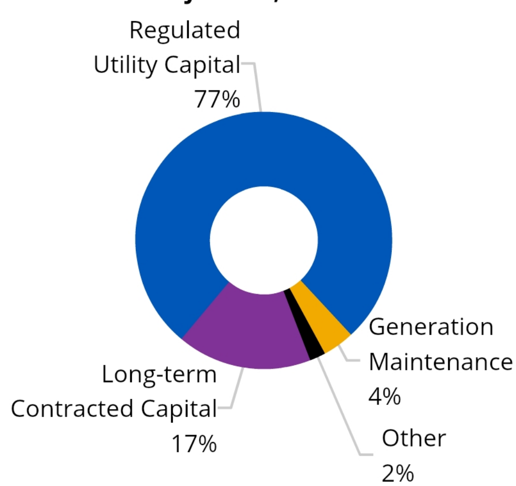


CAPITAL INVESTMENT

Total capital investment in the second quarter of 2019 was $241 million. Of this capital invested, $215 million was invested in Regulated Utilities. These investments earn a return under a regulated business model. The remaining $26 million invested in the second quarter of 2019 included planned capital maintenance in the electricity generation fleet.

Total capital investment in the first half of 2019 was $556 million. Of this capital invested, $428 million was invested in Regulated Utilities, and $95 million was invested in long-term contracted assets including Alberta PowerLine. These investments earn a return under a regulated business model or are commercially secured long-term contracts. The remaining $33 million invested in the first half of 2019 included planned capital maintenance in the electricity generation fleet.

Capital Investment for the Six Months Ended June 30, 2019



GLOBAL BUSINESS UNIT PERFORMANCE

REVENUES

Electricity revenues of $516 million in the second quarter of 2019, and $1,206 million in the first half of 2019, were $118 million and $327 million lower than the same periods in 2018, mainly due to reduced construction activity for APL, partially offset by the settlement of the electricity transmission 2013-2014 deferral application.

ELECTRICITY ADJUSTED EARNINGS

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Regulated Electricity						
Electricity Distribution	**31**	27	4	**69**	60	9
Electricity Transmission	**59**	50	9	**104**	90	14
Total Regulated Electricity Adjusted Earnings	**90**	77	13	**173**	150	23
Non-regulated Electricity						
Independent Power Plants	**(4)**	3	(7)	**10**	(2)	12
Thermal PPA Plants	**8**	13	(5)	**15**	27	(12)
International Electricity Generation	**1**	2	(1)	**6**	7	(1)
Alberta PowerLine	**11**	5	6	**18**	15	3
Total Non-regulated Electricity Adjusted Earnings	**16**	23	(7)	**49**	47	2
Total Electricity Adjusted Earnings	**106**	100	6	**222**	197	25

Electricity earnings were $106 million in the second quarter of 2019, $6 million higher compared to the same period in 2018. Higher earnings were mainly due to the impact of the electricity transmission 2018-2019 general tariff application (GTA) decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes, partially offset by lower availability and higher maintenance costs due to planned outages in the electricity generation business.

Electricity earnings were $222 million in the first half of 2019, $25 million higher than the same period in 2018. Higher earnings were mainly due to the impact of the 2018-2019 GTA decision, continued growth in the regulated rate base, higher market prices in Independent Power Plants, cost efficiencies, and lower income taxes.

Detailed information about the activities and financial results of Electricity's businesses is provided in the following sections.

REGULATED ELECTRICITY

Regulated Electricity provides regulated electricity distribution, transmission and distributed generation mainly in northern and central east Alberta, the Yukon and the Northwest Territories.

Electricity Distribution

Electricity distribution recorded adjusted earnings of $31 million and $69 million in the second quarter and first half of 2019, $4 million and $9 million higher than the same periods in 2018. Higher earnings were mainly due to continued growth in the rate base, cost efficiencies and lower income taxes.

Electricity Transmission

Electricity transmission recorded adjusted earnings of $59 million and $104 million in the second quarter and first half of 2019, $9 million and $14 million higher than the same periods in 2018. Higher adjusted earnings were mainly due to the impact of the 2018-2019 GTA decision, which increased second quarter 2019 adjusted earnings by $17 million of which $4 million relates to the second quarter 2019, $4 million relates to the first quarter 2019, and $9 million relates to 2018. Higher earnings were partially offset by the timing of certain operating expenses and revenues.

NON-REGULATED ELECTRICITY

Non-regulated electricity activities supply electricity from natural gas, coal-fired and hydroelectric generating plants in western Canada, Ontario, Australia and Mexico and non-regulated electricity transmission in Alberta.

Generating Plant Availability

Electricity generating availability for the second quarter and first half of 2019 and 2018 is shown in the table below. Generating plant capacity fluctuates with the timing and duration of outages.

		Three Months Ended June 30			Six Months Ended June 30	
	2019	**2018**	**Change**	**2019**	**2018**	**Change**
Independent Power Plants	**87%**	91%	(4%)	**92%**	92%	–
Thermal PPA Plants	**98%**	95%	3%	**97%**	94%	3%
International Electricity Generation	**90%**	97%	(7%)	**95%**	98%	(3%)

Lower availability in our Independent Power Plants in the second quarter of 2019 was mainly due to higher planned outages compared to the second quarter of 2018. In the second quarter of 2019, work was completed at several power plants.

Higher availability in our Thermal PPA Plants in the second quarter and first half of 2019 was primarily due to fewer planned outages. In the first quarter of 2018, a planned minor outage was completed at the Battle River unit 5 plant. Effective January 1, 2019, Battle River unit 5 is categorized under Independent Power Plants.

Availability in our International Electricity Generation Plants in the second quarter and first half of 2019 was lower than the same periods in 2018 mainly due to a planned maintenance outage at the Osborne power plant in the second quarter of 2019.

Alberta Power Market Summary

Average Alberta Power Pool and natural gas prices and the resulting spark spreads for the second quarter and first half of 2019 and 2018 are shown in the table below.

	Three Months Ended June 30			Six Months Ended June 30		
	2019	**2018**	**Change**	**2019**	**2018**	**Change**
Average Alberta Power Pool electricity price *($/MWh)*	**56.37**	56.01	0.36	**63.55**	45.52	18.03
Average natural gas price *($/GJ)*	**0.98**	1.14	(0.16)	**1.73**	1.55	0.18
Average market spark spread ($/*MWh*)	**49.03**	47.45	1.58	**50.56**	33.90	16.66

The average Alberta Power Pool electricity price for the second quarter of 2019 was comparable to the same period in 2018.

The average Alberta Power Pool electricity price for the first half of 2019 was $18.03 per MWh higher compared to the same period in 2018. The increase was due to strong pricing in February and early March as a result of near record low temperatures leading to greater demand, coal unit outages, record low wind capacity factors, and export prices impacting tie line flows.

Realized Forwards Sales Program

	Three Months Ended June 30			Six Months Ended June 30		
	2019	**2018**	**Change**	**2019**	**2018**	**Change**
Average volumes settled *(MW)*	**318**	281	37	**370**	255	115
Average realized spark spread *($/MWh)*	**26.44**	17.31	9.13	**27.78**	16.96	10.82

In the second quarter of 2019, Independent Power Plants sold forward 318 MW of power that settled at an average realized spark spread of $26.44 per MWh compared to 281 MW sold forward that settled at an average of $17.31 per MWh in the same period of 2018. Forward sales in 2019 resulted in a realized loss position comparable to the same period in 2018 due to the realized spark spread being lower than the market spark spread of $49.03 per MWh, shown above in the Alberta Power Market Summary.

In the first half of 2019, Independent Power Plants sold forward 370 MW of power that settled at an average realized spark spread of $27.78 per MWh compared to 255 MW sold forward that settled at an average of $16.96 per MWh during the first half of 2018. Forward sales in 2019 resulted in a higher realized loss position compared to the same period in 2018 due to the realized spark spread being lower than the market spark spread of $50.56 per MWh, shown above in the Alberta Power Market Summary.

Independent Power Plants

Independent Power Plants recorded an adjusted loss of $4 million in the second quarter of 2019, compared to $3 million of earnings in the same period in 2018. Lower earnings generated by Independent Power Plants were mainly due to lower availability and higher maintenance costs due to planned outages in the second quarter of 2019. While Battle River unit 5 was categorized under Independent Power Plants in 2019, the market in the second quarter of 2019 did not provide opportunities to achieve earnings similar to those achieved through the Thermal PPA in the same period in 2018.

Independent Power Plants recorded adjusted earnings of $10 million in the first half of 2019, $12 million higher compared to the same period in 2018. Higher earnings generated by Independent Power Plants were mainly due to increased market prices and lower general and administrative costs, partially offset by higher maintenance costs and realized losses on forward sales.

Thermal PPA Plants

The electricity generated by the Sheerness units, and by Battle River unit 5 until September 30, 2018, is sold through PPAs. Under the PPAs, generating capacity for each generating unit must be made available to the PPA purchaser of that unit. These arrangements entitle us to recover forecast fixed and variable costs from the PPA purchaser. An operations and maintenance margin is included on these fixed and variable costs and is recognized over the term of the PPAs. Under the terms of the PPAs, counterparties are also subject to an incentive related to the generating unit availability. Incentives are payable by the PPA counterparties for availability in excess of predetermined targets.

Thermal Power Plants recorded adjusted earnings of $8 million in the second quarter of 2019 and $15 million in the first half of 2019, $5 million and $12 million lower than the same periods in 2018. Lower earnings were mainly due to Battle River unit 5 earnings being categorized under Independent Power Plants effective January 1, 2019.

International Electricity Generation

International electricity generation activities supply electricity from two natural gas-fired electricity generation plants in Australia: the Osborne plant in South Australia and the Karratha plant in Western Australia. Electricity is also supplied from a distributed electricity generation station near San Luis Potosí, Mexico and a hydroelectric generation station near Veracruz, Mexico.

International electricity generation recorded adjusted earnings of $1 million in the second quarter of 2019 and $6 million in the first half of 2019, $1 million lower than the same periods in 2018. Lower earnings were mainly due to the impact of the new Osborne Power Purchase Agreement which came into effect in December 2018.

Alberta PowerLine

Alberta PowerLine is a partnership between Canadian Utilities (80 per cent) and Quanta Services, Inc. (20 per cent), with a 35-year contract from the Alberta Electric System Operator (AESO) to design, build, own, and operate the 500 km, Fort McMurray West 500-kV Transmission project, running from Wabamun, near Edmonton to Fort McMurray, Alberta.

APL's adjusted earnings were $11 million and $18 million in the second quarter and first half of 2019, $6 million and $3 million higher compared to the same periods in 2018. Higher earnings were mainly due to lower income taxes from lower Alberta corporate income tax rates, and higher service concession arrangement interest income, partially offset by lower earnings from the completion of construction activity in the first quarter of 2019.

ELECTRICITY RECENT DEVELOPMENTS

Alberta PowerLine

In June 2019, Canadian Utilities, along with its partner Quanta Services Inc., entered into definitive agreements for the sale of Alberta PowerLine Limited Partnership (APL) through a competitive process for total proceeds of approximately $300 million, and the assumption of approximately $1.4 billion of APL debt. The purchaser is a consortium including Greystone Managed Investments doing business as TD Greystone Asset Management, as manager for and on behalf of the Greystone Infrastructure Fund (Global Master) L.P., and IST3 Investment Foundation acting in respect and on behalf of its investment group IST3 Infrastruktur Global. As part of these agreements, Canadian Utilities is offering an opportunity for Indigenous communities along the transmission line route to obtain up to a 40 per cent equity interest in APL. The final ownership mix will be determined upon close of the purchase option for Indigenous communities. Canadian Utilities will remain as operator of APL over its 35-year contract with the AESO. The sale is expected to close in the fourth quarter of 2019, subject to receipt of regulatory approvals and satisfaction of other customary closing conditions.

Sale of Electricity Generation Business

In May 2019, Canadian Utilities entered into definitive agreements to sell its entire Canadian fossil fuel-based electricity generation portfolio for aggregate proceeds of approximately $835 million, subject to customary closing adjustments. An agreement with Heartland Generation Ltd., an affiliate of Energy Capital Partners, includes 10 partly or fully-owned natural gas-fired and coal-fired electricity generation assets located in Alberta and British Columbia (BC). Subsequent to the agreement with Heartland Generation Ltd., Ontario Power Generation Inc. exercised a right of first refusal to acquire Canadian Utilities' 50 per cent ownership in the 580 MW Brighton Beach Power joint venture. These transactions are expected to close in the second half of 2019. In a separate transaction, Canadian Utilities entered into an agreement to sell its 50 per cent ownership interest in the 260 MW Cory Cogeneration Station to SaskPower International. The Cory Cogeneration Station sale transaction closed in July 2019.

REVENUES

Pipelines & Liquids revenues of $355 million in the second quarter of 2019, and $832 million in the first half of 2019, were $40 million and $32 million higher than the same periods in 2018. Higher revenues were mainly due to higher flow-through revenues in natural gas distribution for third party franchise and transmission fees, and growth in the regulated rate base.

PIPELINES & LIQUIDS ADJUSTED EARNINGS

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Regulated Pipelines & Liquids						
Natural Gas Distribution	**3**	(4)	7	**75**	63	12
Natural Gas Transmission	**22**	18	4	**38**	36	2
International Natural Gas Distribution	**14**	14	–	**22**	28	(6)
Total Regulated Pipelines & Liquids Adjusted Earnings	**39**	28	11	**135**	127	8
Non-regulated Pipelines & Liquids						
Storage & Industrial Water	**3**	(1)	4	**5**	1	4
Total Pipelines & Liquids Adjusted Earnings	**42**	27	15	**140**	128	12

Pipelines & Liquids recorded adjusted earnings of $42 million in the second quarter of 2019 and $140 million in the the first half of 2019, $15 million and $12 million higher than the same periods in 2018. Higher earnings were mainly due to ongoing growth in the regulated rate base and the impact of the natural gas transmission 2019-2020 general rate application (GRA) decision, earnings growth in the hydrocarbon storage business, cost efficiencies, and lower income taxes.

Detailed information about the activities and financial results of Pipelines & Liquids' businesses is provided in the following sections.

REGULATED PIPELINES & LIQUIDS

Natural Gas Distribution

Natural gas distribution services municipal, residential, business and industrial customers throughout Alberta and in the Lloydminster area of Saskatchewan.

Natural gas distribution recorded adjusted earnings of $3 million and $75 million in the second quarter and first half of 2019, $7 million and $12 million higher than the same periods in 2018, mainly due to cost efficiencies, growth in the rate base, and lower income taxes.

Natural Gas Transmission

Natural gas transmission receives natural gas on its pipeline system from various gas processing plants as well as from other natural gas transmission systems and transports it to end users within the province of Alberta or to other pipeline systems, primarily for export out of the province.

Natural gas transmission recorded adjusted earnings of $22 million in the second quarter of 2019 and $38 million in the first half of 2019, $4 million and $2 million higher than the same periods in 2018. Higher adjusted earnings were mainly due to the receipt of an AUC decision on applied-for rates in the 2019-2020 GRA, which increased second quarter adjusted earnings by approximately $3 million, of which $2 million is related to the first quarter of 2019. Higher earnings were also positively impacted by continued growth in the rate base and lower income taxes.

International Natural Gas Distribution

International natural gas distribution is a regulated provider of natural gas distribution services in Western Australia, serving metropolitan Perth and surrounding regions.

In the second quarter of 2019, international gas distribution adjusted earnings were comparable to the same period in 2018.

The international natural gas distribution business recorded adjusted earnings of $22 million in the first half of 2019, $6 million lower than the same period in 2018, mainly due to significant CPI adjustments in the first quarter offset by interest savings and growth in the rate base. Earnings adjustments are made for the inflation rate published by the Australian Bureau of Statistics. The published inflation rate for the first quarter of 2019, when applied to the rate of return calculations, produced a reduction to the revenues and earnings in the first quarter.

NON-REGULATED PIPELINES & LIQUIDS

Storage & Industrial Water

Storage & industrial water provides industrial water services and non-regulated natural gas and hydrocarbon storage, and transmission activities in Alberta.

The storage & industrial water business recorded adjusted earnings of $3 million in the second quarter of 2019 and $5 million in the first half of 2019, $4 million higher than the same periods in 2018. Higher earnings were mainly due to incremental earnings from two additional hydrocarbon storage caverns that became operational in the second quarter of 2018 and lower income taxes from lower Alberta corporate income tax rates.

CORPORATE & OTHER

Canadian Utilities' Corporate & Other segment includes Retail Energy through ATCOenergy, launched in 2016 to provide retail electricity and natural gas services in Alberta. Corporate & Other also includes the global corporate head office in Calgary, Canada, the Australia corporate head office in Perth, Australia and the Mexico corporate head office in Mexico City, Mexico. Canadian Utilities Corporate and Other also includes CU Inc. and Canadian Utilities preferred share dividend expenses.

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the second quarter of 2019 were $2 million lower compared to the same period in 2018 mainly due to a reduction in value of deferred tax assets in ATCOenergy related to a decrease in Alberta corporate income tax rates.

Including intersegment eliminations, Canadian Utilities Corporate & Other adjusted earnings in the first half of 2019 were $1 million higher compared to the same period in 2018 mainly due to the timing of certain operating costs.

REGULATORY DEVELOPMENTS

ATCO ELECTRIC HANNA REGION TRANSMISSION DEVELOPMENT DEFERRAL APPLICATION

In February 2017, electricity transmission filed an application seeking approval of approximately $688 million of capital additions related to the Hanna Regional Transmission Development program incurred between 2012 and 2015. A decision from the AUC was received in June 2019 approving the vast majority of capital additions as prudently incurred. The adjustments directed by the AUC in the decision had an immaterial impact on earnings.

ATCO PIPELINES 2019-2020 GENERAL RATE APPLICATION (GRA)

In July 2018, natural gas transmission filed a GRA for 2019 and 2020. The decision was received in June 2019 approving the majority of requested capital expenditures and operating costs requested as filed. The adjustments directed by the AUC in the decision had a $3 million positive impact on second quarter 2019 adjusted earnings. The revenue associated with the Pembina Keephills Transmission Pipeline project will remain a placeholder pending its separate facilities decision.

ATCO ELECTRIC 2018-2019 GENERAL TARIFF APPLICATION (GTA)

In June 2017, electricity transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of requested capital expenditures and operating costs as filed. The impact of this decision is an increase to second quarter 2019 adjusted earnings of $17 million.

INFORMATION TECHNOLOGY (IT) COMMON MATTERS

In August 2014, Canadian Utilities sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million which was recorded in earnings attributable to equity owners of the Company. In 2014, Canadian Utilities did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In 2015, the AUC commenced an Information Technology Common Matters (IT Common Matters) proceeding to review the recovery of information technology costs by the Alberta Utilities from January 1, 2015 going forward. In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding, and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13 per cent and to apply a glide path that reduces pricing by 4.61 per cent in each of years 2 through 10. For the natural gas and electricity distribution utilities, the AUC's direction impacts the 2018 going-in rates and treatment of capital costs. For the natural gas and electricity transmission utilities, the AUC's direction impacts the revenue requirement dating back to 2015. The Alberta Utilities presented a considerable amount of evidence, including independent expert benchmarking and price review studies, to show that the Wipro MSA rates were at fair market value (FMV). As such, there was no cross subsidization between the sale price of Canadian Utilities' IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC determined that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

As a result of the AUC's IT Common Matters decision, a $14 million reduction to the previously recorded 2014 after-tax gain on sale of $138 million has been recorded in the second quarter of 2019. Going forward, the IT Common Matters decision is expected to further reduce the previously recorded gain. Consistent with the treatment in 2014, the $14 million reduction booked in the second quarter of 2019, along with future impacts associated with this decision, will not be included in adjusted earnings.

In July 2019, the Alberta Utilities filed a leave to appeal application with the Alberta Court of Appeal in relation to the AUC Decision on the IT Common Matters proceeding.

ATCO GAS AUSTRALIA ACCESS ARRANGEMENT

International natural gas distribution received the draft decision related to its Access Arrangement 5 (AA5) application from the Economic Regulation Authority (ERA) on April 18, 2019. The ERA also published its final rate of return guidelines which outline the parameters for the weighted average cost of capital (WACC) applicable to AA5. The published guidelines indicate a lower WACC for AA5 with lower earnings expected over the five-year period commencing in 2020. Based on the market risk free rate at June 30, 2019, the ROE component of WACC would be about 200 basis points lower in 2020 compared to the 2019 ROE using the current WACC applicable to Access Arrangement 4. The AA5 WACC (including the ROE) will be completed using a 20-business day period of observation to determine the risk free rate portion of the WACC calculation prior to the final decision.

The final decision from the ERA on AA5 is expected in October 2019 and will include decisions on the main components that influence earnings including: the WACC, the five-year capital expenditure program, the five-year operating cost forecast, the demand forecast of throughput on the natural gas distribution network in Western Australia, and an evaluation of the capital expenditure program completed during the AA4 period to confirm the capital expenditures met the regulatory criteria. A further reduction to achieved ROE is expected to arise from the rebasing of operating costs and the forecast of demand and throughput.

SUSTAINABILITY, CLIMATE CHANGE AND ENERGY TRANSITION

We believe that reducing our environmental impact is integral to the pursuit of operational excellence and long-term sustainable growth. Our success depends on our ability to operate in a responsible and sustainable manner, today and in the future.

SUSTAINABILITY REPORTING

ATCO's annual Sustainability Report, published in June 2019, focuses on material topics including:

- Energy Stewardship: access and affordability, security and reliability, and customer satisfaction,
- Environmental Stewardship: climate change and energy use, and environmental compliance,
- Safety: employee health and safety, public safety, and emergency preparedness, and
- Community and Indigenous relations.

The Sustainability Report is based upon the internationally recognized Global Reporting Initiative (GRI) Standards. Our reporting is also guided by frameworks such as the Sustainability Accounting Standards Board and the Financial Stability Board's Task Force on Climate-related Financial Disclosures' recommendations.

The 2018 Sustainability Report, Sustainability Framework Reference Document, and other disclosures are available on our website, at www.canadianutilities.com.

CLIMATE CHANGE AND ENERGY TRANSITION

To contribute to a lower carbon future, we continue to pursue initiatives looking at integrating lower intensity fuels, such as natural gas, hydrogen, renewables, and other clean energy solutions.

In 2018, we installed three electric vehicle (EV) charging stations between Calgary and Edmonton, Alberta providing end-users an opportunity to replace liquid fuel with a low-carbon emitting energy. In 2019, Canadian Utilities plans to significantly expand its number of EV direct current, fast charging stations in Alberta. The fourth EV station was energized in Canmore in June, with 19 more EV charging stations planned for installation throughout 2019 and 2020.

OTHER EXPENSES AND INCOME

A financial summary of other consolidated expenses and income items for the second quarter and first half of 2019 and 2018 is given below. These amounts are presented in accordance with IFRS accounting standards. They have not been adjusted for the timing of revenues and expenses associated with rate-regulated activities and other items that are not in the normal course of business.

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Operating costs	**504**	524	(20)	**1,033**	1,040	(7)
Service concession arrangement costs	**8**	148	(140)	**103**	516	(413)
Earnings from investment in joint ventures	**4**	4	–	**12**	12	–
Depreciation and amortization	**154**	182	(28)	**311**	333	(22)
Net finance costs	**117**	115	2	**234**	229	5
Income taxes	**(177)**	4	(181)	**(97)**	67	(164)

OPERATING COSTS

Operating costs, which are total costs and expenses less service concession arrangement costs and depreciation and amortization, decreased by $20 million in the second quarter of 2019 when compared to the same period in 2018. Lower operating costs were mainly due to lower salaries and wages, partially offset by unrealized losses on mark-to-market forward commodity contracts in Independent Power Plants.

In the first six months of 2019, operating costs decreased by $7 million. Lower operating costs were mainly due to lower salaries and wages, partially offset by higher flow-through natural gas fuel and power costs from increased activity in Independent Power Plants and ATCOenergy.

SERVICE CONCESSION ARRANGEMENT COSTS

Service concession arrangement costs are recorded for third party construction and operation activities for the Fort McMurray West-500kV Project. Service concession arrangement costs in the second quarter and first half of 2019 were $140 million and $413 million lower compared to the same periods in 2018, mainly due to the completion of APL construction activities in March 2019. The project was energized on March 28, 2019. With the commencement of operations in the second quarter of 2019, costs incurred in this period primarily relate to operating and maintenance activities.

EARNINGS FROM INVESTMENT IN JOINT VENTURES

Earnings from investment in joint ventures is mainly comprised of our ownership position in several electricity generation plants and the Strathcona Storage Limited Partnership which operates hydrocarbon storage facilities near Fort Saskatchewan, Alberta.

Earnings in the second quarter and first half of 2019 were comparable to the same periods in 2018.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense decreased by $28 million and $22 million in the second quarter and first half of 2019 when compared to the same periods in 2018, mainly due to higher costs in the second quarter of 2018 related to decisions to discontinue certain projects that no longer represented long-term strategic value to the Company, partially offset by higher depreciation due to continued growth in the regulated rate base.

NET FINANCE COSTS

Net finance costs increased by $2 million and $5 million in the second quarter and first half of 2019 when compared to the same periods in 2018, mainly due to lower interest income on APL cash balances and interest expense associated with the incremental debt issued to fund the ongoing capital investment program in the Regulated Utilities.

INCOME TAXES

Income taxes decreased by $181 million in the second quarter and $164 million in the first half of 2019 when compared to the same periods in 2018 mainly due to lower corporate income tax rates enacted by the Government of Alberta in June 2019, partially offset by higher earnings before income taxes. In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent over four years, commencing with a one per cent decrease on July 1, 2019, followed by one per cent reductions on January 1 of each of the next three years.

LIQUIDITY AND CAPITAL RESOURCES

Our financial position is supported by Regulated Utility and long-term contracted operations. Our business strategies, funding of operations, and planned future growth are supported by maintaining strong investment grade credit ratings and access to capital markets at competitive rates. Primary sources of capital are cash flow from operations and the debt and preferred share capital markets.

We consider it prudent to maintain enough liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Liquidity is generated by cash flow from operations and is supported by appropriate levels of cash and available committed credit facilities.

CREDIT RATINGS

Credit ratings are important to the Company's financing costs and ability to raise funds. The Company intends to maintain strong investment grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.

On July 17, 2019, Dominion Bond Rating Service affirmed its 'A (high)' long-term corporate credit rating and stable outlook on Canadian Utilities' subsidiary CU Inc.

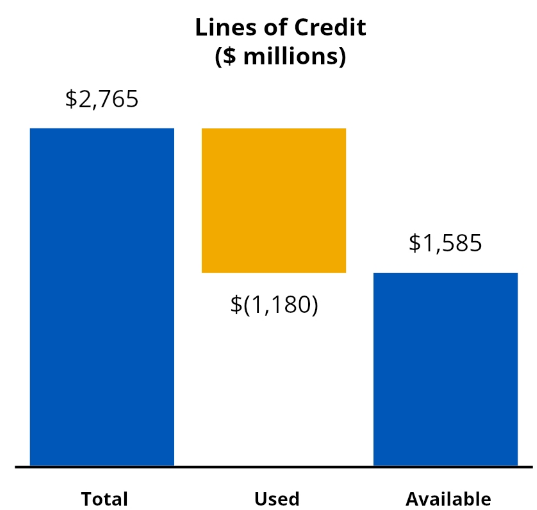
LINES OF CREDIT

At June 30, 2019, Canadian Utilities and its subsidiaries had the following lines of credit.

($ millions)	**Total**	**Used**	**Available**
Long-term committed	**2,211**	918	1,293
Uncommitted	**554**	262	292
Total	**2,765**	1,180	1,585

Of the $2,765 million in total credit lines, $554 million was in the form of uncommitted credit facilities with no set maturity date. The other $2,211 million in credit lines was committed, with maturities between 2020 and 2023, and may be extended at the option of the lenders.

Of the $1,180 million credit line usage,$365 million was related to ATCO Gas Australia Pty Ltd. and $550 million was related to issuances of commercial paper that are back-stopped by the corporate credit facilities. The majority of the remaining usage was associated with the issuance of letters of credit. Long-term committed credit lines are used to satisfy all of ATCO Gas Australia Pty Ltd.'s term debt financing needs.



CONSOLIDATED CASH FLOW

At June 30, 2019, the Company's cash position was $601 million, an increase of $2 million compared to December 31, 2018. The increase was mainly due to higher adjusted earnings achieved and lower capital investment during the first half of 2019.

Funds Generated by Operations

Funds generated by operations were $390 million in the second quarter of 2019 and $941 million in the first half of 2019, $94 million and $120 million higher than the same periods in 2018. The increase was mainly due to higher earnings, the 2018 impact of a refund of customer deferral accounts in electricity transmission and a refund of over collected transmission costs in natural gas distribution.

Cash Used for Capital Investment

Cash used for capital investment was $241 million in the second quarter of 2019, $201 million lower than the same period in 2018. Lower capital spending was mainly due to lower planned capital investment in Alberta PowerLine natural gas distribution, electricity distribution, and international natural gas distribution, partially offset by higher capital investment for planned maintenance of electricity generation assets.

Cash used for capital investment was $556 million in the first half of 2019, $630 million lower than the same period in 2018. Lower capital spending was mainly due to lower planned capital investment in all business units. Electricity generation capital investment in the first half of 2018 included the $112 million acquisition of the Mexico hydroelectric facility.

Capital investment in the second quarter and first half of 2019 and 2018 is shown in the table below.

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	**2019**	**2018**	**Change**	**2019**	**2018**	**Change**
Electricity						
Electricity Distribution	**43**	60	(17)	**88**	106	(18)
Electricity Transmission	**44**	51	(7)	**107**	120	(13)
Electricity Generation	**21**	16	5	**25**	132	(107)
Alberta PowerLine	**–**	148	(148)	**95**	516	(421)
Total Electricity	**108**	275	(167)	**315**	874	(559)
Pipelines & Liquids						
Natural Gas Distribution	**60**	80	(20)	**104**	135	(31)
Natural Gas Transmission	**49**	47	2	**94**	111	(17)
International Natural Gas Distribution	**19**	29	(10)	**35**	45	(10)
International Natural Gas Transmission and Storage & Industrial Water	**4**	8	(4)	**6**	14	(8)
Total Pipelines & Liquids	**132**	164	(32)	**239**	305	(66)
Corporate & Other	**1**	3	(2)	**2**	7	(5)
Canadian Utilities Total (1) (2)	**241**	442	(201)	**556**	1,186	(630)

(1) Includes capital expenditures in joint ventures of $1 million and $1 million (2018 - $3 million and $8 million) for the second quarter and first half of 2019.

(2) Includes additions to property, plant and equipment, intangibles and $4 million and $9 million (2018 - $5 million and $10 million) of interest capitalized during construction for the second quarter and first half of 2019.

Base Shelf Prospectuses

CU Inc. Debentures

On June 11, 2018, CU Inc. filed a base shelf prospectus that permits it to issue up to an aggregate of $1.5 billion of debentures over the 25-month life of the prospectus. As of July 24, 2019, aggregate issuances of debentures were $385 million.

Canadian Utilities Debt Securities and Preferred Shares

On June 11, 2018, Canadian Utilities filed a base shelf prospectus that permits it to issue up to an aggregate of $2 billion of debt securities and preferred shares over the 25-month life of the prospectus. No debt securities or preferred shares have been issued to date under this base shelf prospectus.

Dividends and Common Shares

We have increased our common share dividend each year since 1972, a 47-year track record. Dividends paid to Class A and Class B share owners totaled $116 million in the second quarter and $231 million in the first half of 2019.

On July 9, 2019, the Board of Directors declared a third quarter dividend of 42.27 cents per share. The payment of any dividend is at the discretion of the Board of Directors and depends on our financial condition and other factors.

47 year
track record of increasing common share dividends

Canadian Utilities Dividend Reinvestment Plan (DRIP)

Effective January 10, 2019, Canadian Utilities' DRIP was suspended and no Class A non-voting shares were issued under its DRIP.

SHARE CAPITAL

Canadian Utilities' equity securities consist of Class A shares and Class B shares.

At July 23, 2019, we had outstanding 199,420,216 Class A shares, 73,735,780 Class B shares, and options to purchase 774,629 Class A shares.

CLASS A NON-VOTING SHARES AND CLASS B COMMON SHARES

Class A and Class B share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B share owners are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares and if it would result in the offeror owning more than 50 per cent of the outstanding Class B shares (excluding any Class B shares acquired upon conversion of Class A shares), the Class A share owners are entitled, for the duration of the take-over bid, to exchange their Class A shares for Class B shares and to tender the newly exchanged Class B shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A share owners are entitled to exchange their shares for Class B shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

Of the 12,800,000 Class A shares authorized for grant of options under our stock option plan, 5,154,950 Class A shares were available for issuance at June 30, 2019. Options may be granted to officers and key employees of the Company and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the grant date. The vesting provisions and exercise period (which cannot exceed 10 years) are determined at the time of grant.

QUARTERLY INFORMATION

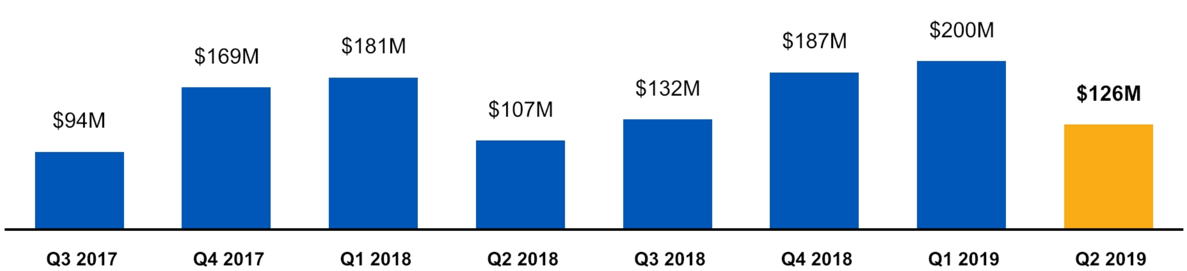
The following table shows financial information for the eight quarters ended September 30, 2017 through June 30, 2019.

($ millions, except for per share data)	Q3 2018	Q4 2018	Q1 2019	Q2 2019
Revenues	990	1,035	1,189	**902**
Earnings attributable to equity owners of the Company	202	256	217	**299**
Earnings attributable to Class A and B shares	185	239	200	**283**
Earnings per Class A and Class B share *($)*	0.68	0.87	0.73	**1.03**
Diluted earnings per Class A and Class B share *($)*	0.68	0.87	0.73	**1.03**
Adjusted earnings per Class A and Class B share *($)*	0.49	0.69	0.73	**0.46**
Adjusted earnings				
Electricity	134	103	116	**106**
Pipelines & Liquids	17	102	98	**42**
Corporate & Other and Intersegment Eliminations	(19)	(18)	(14)	**(22)**
Total adjusted earnings	132	187	200	**126**
($ millions, except for per share data)	**Q3 2017 (1)**	**Q4 2017 (1)**	**Q1 2018**	**Q2 2018**
Revenues	930	1,208	1,385	967
Earnings (loss) attributable to equity owners of the Company	94	102	179	(3)
Earnings (loss) attributable to Class A and Class B shares	78	85	162	(19)
Earnings (loss) per Class A and Class B share *($)*	0.29	0.32	0.60	(0.07)
Diluted earnings (loss) per Class A and Class B share *($)*	0.29	0.32	0.60	(0.07)
Adjusted earnings per Class A and Class B share *($)*	0.35	0.63	0.67	0.39
Adjusted earnings				
Electricity	88	95	97	100
Pipelines & Liquids	24	94	101	27
Corporate & Other and Intersegment Eliminations	(18)	(20)	(17)	(20)
Total adjusted earnings	94	169	181	107

(1) These numbers have been restated to account for the impact of IFRS 15 adopted on January 1, 2018.

ADJUSTED EARNINGS

Our financial results for the previous eight quarters reflect continued growth and regulatory decisions in Regulated Utility operations as well as fluctuating commodity prices in electricity generation and sales, and natural gas storage operations. Interim results will vary due to the seasonal nature of demand for electricity and natural gas, and the timing of utility regulatory decisions.



ELECTRICITY

Electricity adjusted earnings are impacted by the timing of certain major regulatory decisions, and Alberta Power Pool pricing and spark spreads.

In 2017, third quarter earnings included the adverse impact of the 2013 to 2014 Deferral Accounts decision in electricity transmission. Fourth quarter 2017 earnings were impacted by lower contributions in the electricity generation business from forward sales and increased business development expenses.

In 2018, earnings were adversely impacted by performance base regulation rate rebasing under Alberta's regulated model in electricity distribution and lower electricity transmission interim rates approved by the AUC.

In the first quarter of 2018, Electricity earnings were adversely impacted by realized forward sales and minor plant outage costs in the Independent Power Plants, partially offset by earnings from Alberta PowerLine due to construction activity and earnings in Thermal PPAs due to the recognition of availability incentives.

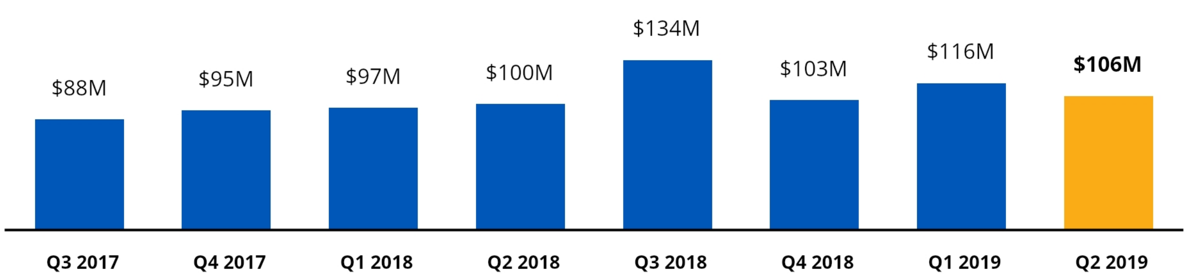
In the second quarter of 2018, earnings increased compared to the second quarter of 2017 mainly due to improved market conditions for Independent Power Plants and higher recognition of availability incentives in the Thermal PPA Plants.

In the third quarter of 2018, earnings increased compared to the third quarter of 2017 mainly due to the completion of performance obligations and additional availability incentive earnings which resulted from the Battle River unit 5 PPA termination, and improved market conditions for Independent Power Plants. These improved earnings were partially offset by lower earnings due to lower scheduled construction activity at Alberta PowerLine.

In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to earnings from the sale of the Barking Power assets and improved conditions in the Alberta power market, as well as higher APL earnings recorded as result of an early energization incentive.

In the first quarter of 2019, higher earnings were mainly due to increased Alberta power market prices, ongoing growth in the regulated rate base and cost efficiencies in electricity distribution.

In the second quarter of 2019, higher earnings compared to the second quarter of 2018 were mainly due to the impact of the electricity transmission 2018-2019 GTA decision, continued growth in the regulated rate base, cost efficiencies, and lower income taxes.



PIPELINES & LIQUIDS

Pipelines & Liquids' adjusted earnings are impacted by the timing of certain major regulatory decisions, seasonality, and demand for hydrocarbon and natural gas storage and water services.

In the third quarter of 2017, earnings were impacted by inflation adjustments to rates in our international natural gas distribution business. Higher earnings in the fourth quarter of 2017 were mainly a result of rate base growth across Pipelines & Liquids' regulated utilities.

In 2018, earnings were adversely impacted by performance base regulation rate rebasing under Alberta's regulated model in natural gas distribution.

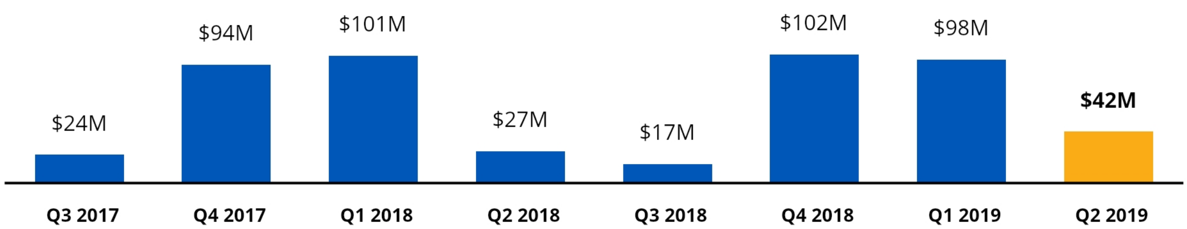
In the first quarter of 2018, earnings were positively impacted by higher seasonal demand and growth in rate base across the Pipelines & Liquids' Regulated businesses.

In the second and third quarters of 2018, lower earnings compared to the same periods in 2017 were mainly due to lower seasonal demand and the impact of rate rebasing under Alberta's regulated model in natural gas distribution, partially offset by growth in rate base across our Regulated Pipelines & Liquids businesses.

In the fourth quarter of 2018, higher earnings compared to the fourth quarter of 2017 were mainly due to growth in rate base, the timing of regulatory decisions and higher seasonal demand.

In the first quarter of 2019, lower earnings compared to the first quarter of 2018 were mainly due to inflation rate adjustments applied to the rate of return calculations in international natural gas distribution, partially offset by ongoing growth in the regulated rate base and cost efficiencies in natural gas distribution.

In the second quarter of 2019, higher earnings compared to the second quarter of 2018 were mainly due to ongoing growth in the regulated rate base and the impact of the natural gas transmission 2019-2020 general rate application GRA decision, earnings growth in the hydrocarbon storage business, cost efficiencies, and lower income taxes.



EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Earnings attributable to equity owners of the Company includes timing adjustments related to rate-regulated activities and unrealized gains or losses on mark-to-market forward commodity contracts. They also include one-time gains and losses, significant impairments, restructuring charges and other items that are not in the normal course of business or a result of day-to-day operations recorded at various times over the past eight quarters. These items are excluded from adjusted earnings and are highlighted below:

- In the fourth quarter of 2017, Structures & Logistics recognized an impairment relating to workforce housing assets in Canada and space rental assets in the U.S. Structures & Logistics determined these assets were impaired due to a reduction in utilization, sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key customers. The Company's 24.5 per cent share of the impairment decreased equity earnings by $7 million in the Corporate & Other segment.
- In the fourth quarter of 2017, the Company recorded an increase to earnings of $31 million on derecognition of customer contributions related to a sale of electricity generation assets on transitioning to finance lease accounting which resulted from the implementation of IFRS 15.
- In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.
- In the third quarter of 2018, the Battle River unit 5 PPA was terminated by the Balancing Pool and dispatch control was returned to Canadian Utilities. Canadian Utilities received a payment from the Balancing Pool and also recorded additional coal-related costs and Asset Retirement Obligations associated with the Battle River generating facility. This one-time receipt and costs in the net amount of $36 million was excluded from adjusted earnings.
- In the fourth quarter of 2018, Canadian Utilities sold its 100 per cent ownership interest in Barking Power assets. A gain in the amount of $87 million was excluded from adjusted earnings.
- In the second quarter of 2019, Canadian Utilities recorded transaction costs of $8 million for the pending sale of the Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine Limited Partnership. These costs are related to one-time transactions and are therefore excluded from adjusted earnings.

NON-GAAP AND ADDITIONAL GAAP MEASURES

Adjusted earnings are defined as earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings present earnings from rate-regulated activities on the same basis as was used prior to adopting IFRS - that basis being the U.S. accounting principles for rate-regulated activities. Management’s view is that adjusted earnings allow for a more effective analysis of operating performance and trends. A reconciliation of adjusted earnings to earnings attributable to equity owners of the Company is presented in this MD&A. Adjusted earnings is an additional GAAP measure presented in Note 4 of the unaudited interim consolidated financial statements.

Adjusted earnings per Class A and Class B share is calculated by dividing adjusted earnings by the weighted average number of shares outstanding for the period.

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management’s opinion, funds generated by operations is a significant performance indicator of the Company’s ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. A reconciliation of funds generated by operations to cash flows from operating activities is presented in this MD&A.

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

RECONCILIATION OF ADJUSTED EARNINGS TO EARNINGS ATTRIBUTABLE TO EQUITY OWNERS OF THE COMPANY

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses associated with rate-regulated activities, dividends on equity preferred shares of the Company, and unrealized gains or losses on mark-to-market forward commodity contracts. Adjusted earnings also exclude one-time gains and losses, significant impairments, and items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings that management uses to assess segment performance and allocate resources. It is management's view that adjusted earnings allow a better assessment of the economics of rate regulation in Canada and Australia than IFRS earnings.

($ millions)					**Three Months Ended June 30**
2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues	**516**	**355**	**49**	**(18)**	**902**
	634	315	37	(19)	967
Adjusted earnings (loss)	**106**	**42**	**(24)**	**2**	**126**
	100	27	(20)	–	107
Transaction costs	**(8)**	**–**	**–**	**–**	**(8)**
	–	–	–	–	–
Restructuring and other costs	**–**	**–**	**–**	**–**	**–**
	(36)	(19)	(5)	–	(60)
Unrealized (losses) gains on mark-to-market forward commodity contracts	**(5)**	**–**	**–**	**–**	**(5)**
	12	–	–	–	12
Rate-regulated activities	**120**	**68**	**–**	**(4)**	**184**
	(53)	(22)	–	1	(74)
IT Common Matters decision	**(7)**	**(7)**	**–**	**–**	**(14)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**14**	**–**	**16**
	1	–	15	–	16
Other	**–**	**–**	**–**	**–**	**–**
	–	(4)	–	–	(4)
Earnings (loss) attributable to equity owners of the Company	**207**	**104**	**(10)**	**(2)**	**299**
	24	(18)	(10)	1	(3)

($ millions)					Six Months Ended June 30
2019 / 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues	**1,206**	**832**	**118**	**(65)**	**2,091**
	1,533	800	76	(57)	2,352
Adjusted earnings (loss)	**222**	**140**	**(38)**	**2**	**326**
	197	128	(37)	–	288
Transaction costs	**(8)**	–	–	–	**(8)**
	–	–	–	–	–
Restructuring and other costs	–	–	–	–	–
	(36)	(19)	(5)	–	(60)
Unrealized (losses) gains on mark-to-market forward commodity contracts	**1**	–	–	–	**1**
	(6)	–	–	–	(6)
Rate-regulated activities	**117**	**63**	–	**(3)**	**177**
	(66)	(13)	–	2	(77)
IT Common Matter decision	**(7)**	**(7)**	–	–	**(14)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**2**	**29**	–	**33**
	2	–	31	–	33
Other	–	**1**	–	–	**1**
	–	(2)	–	–	(2)
Earnings (loss) attributable to equity owners of the Company	**327**	**199**	**(9)**	**(1)**	**516**
	91	94	(11)	2	176

TRANSACTION COSTS

In the second quarter of 2019, the Company incurred transaction costs for the announced sales of the Canadian fossil fuel-based electricity generation portfolio and Alberta PowerLine Limited Partnership. As these costs are related to one-time transactions, they are excluded from adjusted earnings.

RESTRUCTURING AND OTHER COSTS

In the second quarter of 2018, restructuring and other costs not in the normal course of business of $60 million were recorded. These costs mainly relate to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represent long-term strategic value to the Company.

UNREALIZED GAINS (LOSSES) ON MARK-TO-MARKET FORWARD COMMODITY CONTRACTS

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

RATE-REGULATED ACTIVITIES

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as Regulated Utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the Regulated Utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Regulated Utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company's rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulator's decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

Timing Adjustment	Items	RRA Treatment	IFRS Treatment
Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

The significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	Three Months Ended June 30			Six Months Ended June 30		
($ millions)	2019	2018	Change	2019	2018	Change
Additional revenues billed in current period						
Future removal and site restoration costs (1)	**16**	20	(4)	**36**	39	(3)
Impact of colder temperatures (2)	**–**	–	–	**12**	12	–
Revenues to be billed in future periods						
Deferred income taxes (3)	**(28)**	(26)	(2)	**(56)**	(59)	3
Deferred income taxes due to decrease in provincial corporate tax (4)	**203**	–	203	**203**	–	203
Impact of inflation on rate base (5)	**(4)**	–	(4)	**(4)**	–	(4)
Regulatory decisions received (see below)	**(3)**	–	(3)	**(3)**	–	(3)
Settlement of regulatory decisions and other items (6)	**–**	(68)	68	**(11)**	(69)	58
	184	(74)	258	**177**	(77)	254

(1) *Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.*

(2) *ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.*

(3) *Income taxes are billed to customers when paid by the Company.*

(4) *In the second quarter of 2019, the Government of Alberta announced a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022. As a result of this change, the Alberta Utilities decreased deferred income taxes and increased earnings for the three and six months ended June 30, 2019 by $203 million.*

(5) *The inflation-indexed portion of ATCO Gas Australia's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current period for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.*

(6) *In the second quarter of 2018, ATCO Electric recorded a decrease in earnings for the period of $38 million mainly related to the refund of deferral account balances for 2013 and 2014. ATCO Gas also recorded a reduction in earnings for the period of $23 million related to the refund of previously over collected transmission costs.*

Regulatory Decisions Received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. A description of the significant regulatory decisions recognized in adjusted earnings in 2019 is provided below.

	Decision	Amount	Description
1.	Information Technology (IT) Common Matters	14	In August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. In 2015, the AUC commenced an Information Technology Common Matters proceeding to review the recovery of IT costs by the Alberta Utilities from January 1, 2015 going forward. On June 5, 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13% and to apply a glide path that reduces pricing by 4.61% in each of years 2 through 10. The reduction in adjusted earnings resulting from the decision for the period January 1, 2015 to June 30, 2019 of $14 million was recorded in the second quarter of 2019.
2.	ATCO Electric Transmission General Tariff Application (GTA)	(17)	In June 2017, ATCO Electric filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision of $17 million was recorded in the second quarter of 2019.

IT COMMON MATTERS DECISION

As described in the IT Common Matters decision above, in August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding which is described in the regulatory decisions received section above. In the proceeding, the Company presented a considerable amount of evidence, including expert benchmarking and price review studies, to support that the Wipro MSA rates were at fair market value. As such, there was no cross subsidization between the sale price of the Company's IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC found that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

Consistent with the treatment in 2014, the $14 million reduction booked in the second quarter of 2019, along with future impacts associated with this decision, will not be included in adjusted earnings.

OTHER

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. For the three and six months ended June 30, 2019, the Company recorded a foreign exchange gain of nil and $1 million, respectively (2018 - a foreign exchange loss of $4 million and $2 million) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

RECONCILIATION OF FUNDS GENERATED BY OPERATIONS TO CASH FLOWS FROM OPERATING ACTIVITIES

Funds generated by operations is defined as cash flow from operations before changes in non-cash working capital and change in receivable under service concession arrangement. In management's opinion, funds generated by operations is a significant performance indicator of the Company's ability to generate cash during a period to fund capital expenditures. Funds generated by operations does not have any standardized meaning under IFRS and might not be comparable to similar measures presented by other companies.

($ millions)

2019 **2018**	**Three Months Ended June 30**	**Six Months Ended June 30**
Funds generated by operations	**390**	**941**
	296	821
Changes in non-cash working capital	**(76)**	**(186)**
	(52)	111
Change in receivable under service concession arrangement	**(13)**	**(139)**
	(181)	(580)
Cash flows from operating activities	**301**	**616**
	63	352

RECONCILIATION OF CAPITAL INVESTMENT TO CAPITAL EXPENDITURES

Capital investment is defined as cash used for capital expenditures, business combinations, service concession arrangements, and cash used in the Company's proportional share of capital expenditures in joint ventures. In management's opinion, capital investment reflects the Company's total cash investment in assets. Capital expenditures includes additions to property, plant and equipment and intangibles as well as interest capitalized during construction. A reconciliation of capital investments to capital expenditures is presented in this MD&A.

($ millions) **Three Months Ended June 30**

2019 / **2018**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**108**	**132**	**1**	**241**
	275	164	3	442
Capital Expenditure in joint ventures	–	**(1)**	–	**(1)**
	(1)	(2)	–	(3)
Service concession arrangement	–	–	–	–
	(148)	–	–	(148)
Capital Expenditures	**108**	**131**	**1**	**240**
	126	162	3	291

($ millions) **Six Months Ended June 30**

2019 / **2018**	**Electricity**	**Pipelines & Liquids**	**CUL Corporate & Other**	**Consolidated**
Capital Investment	**315**	**239**	**2**	**556**
	874	305	7	1,186
Capital Expenditure in joint ventures	–	**(1)**	–	**(1)**
	(4)	(4)	–	(8)
Business Combination (1)	–	–	–	–
	(112)	–	–	(112)
Service concession arrangement	**(95)**	–	–	**(95)**
	(516)	–	–	(516)
Capital Expenditures	**220**	**238**	**2**	**460**
	242	301	7	550

(1) Business combination includes Canadian Utilities' acquisition of Electricidad de Golfo, a long-term contracted, 35 MW hydroelectric power station in the state of Veracruz, Mexico.

OTHER FINANCIAL INFORMATION

ACCOUNTING CHANGES

On January 1, 2019, the Company adopted the new accounting standard, IFRS 16 *Leases*, which replaces IAS 17 *Leases* and related interpretations. This standard introduces a new approach to lease accounting that requires a lessee to recognize right-of-use assets and lease liabilities for the rights and obligations created by leases. It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. Lessor accounting under the new standard retains similar classifications to the previous guidance.

The Company adopted the standard using the modified retrospective approach which does not require restatement of prior period financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in the unaudited interim consolidated financial statements is not restated.

On adoption of the new standard on January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The right-of-use assets and lease liabilities relate to leases for land and buildings. From January 1, 2019, the Company recognizes depreciation expense on right-of-use assets and interest expense on lease liabilities with lease payments recorded as a reduction of the lease liability. Prior to the adoption of IFRS 16, lease payments were recorded as expenses in the statement of earnings. The adoption of IFRS 16 has not had a significant impact on earnings. Further information on the adoption of IFRS 16, right-of-use assets and lease liabilities are provided in Notes 3, 9 and 12 of the unaudited interim consolidated financial statements.

In June 2019, the IFRS Interpretations Committee, acting on a request for interpretation, concluded that a pipeline sub-surface arrangement is, or contains, a lease under IFRS 16. A pipeline sub-surface arrangement is an agreement with a landowner to lay an underground pipeline in exchange for consideration. It contains a lease because the underground space is physically distinct from the landowner's land, and the owner of the pipeline has exclusive use of the underground space. The Company is currently assessing the impact of the interpretation on its pipeline sub-surface arrangements. The assessment is expected to be complete before the end of 2019. Based on the preliminary analysis performed to date, the impact on the consolidated financial statements is not expected to be significant.

There are no other new or amended standards issued, but not yet effective, that the Company anticipates will have a material effect on the unaudited interim consolidated financial statements.

INTERNAL CONTROL OVER FINANCIAL REPORTING

There was no change in the Company's internal control over financial reporting that occurred during the period beginning on April 1, 2019, and ended on June 30, 2019, that materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

FORWARD-LOOKING INFORMATION

Certain statements contained in this MD&A constitute forward-looking information. Forward-looking information is often, but not always, identified by the use of words such as "anticipate", "plan", "estimate", "expect", "may", "will", "intend", "should", and similar expressions. Forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information. The Company believes that the expectations reflected in the forward-looking information are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking information should not be unduly relied upon.

The Company's actual results could differ materially from those anticipated in any forward-looking information contained in this MD&A as a result of regulatory decisions, competitive factors in the industries in which the Company operates, prevailing economic conditions, and other factors, many of which are beyond the control of the Company.

Any forward-looking information contained in this MD&A represents the Company's expectations as of the date hereof, and is subject to change after such date. The Company disclaims any intention or obligation to update or revise any forward-looking information whether as a result of new information, future events or otherwise, except as required by applicable securities legislation.

ADDITIONAL INFORMATION

Canadian Utilities has published its unaudited interim consolidated financial statements and its MD&A for the six months ended June 30, 2019. Copies of these documents may be obtained upon request from Investor Relations at 3rd Floor, West Building, 5302 Forand Street S.W., Calgary, Alberta, T3E 8B4, telephone 403-292-7500, fax 403-292-7532 or email investorrelations@atco.com.

GLOSSARY

AESO means the Alberta Electric System Operator.

Alberta Power Pool means the market for electricity in Alberta operated by AESO.

Alberta Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas) and Natural Gas Transmission (ATCO Pipelines).

AUC means the Alberta Utilities Commission.

Availability is a measure of time, expressed as a percentage of continuous operation, that a generating unit is capable of producing electricity, regardless of whether the unit is actually generating electricity.

Class A shares means Class A non-voting shares of the Company.

Class B shares means Class B common shares of the Company.

CODM means Chief Operating Decision Maker, and is comprised of the Chair, Chief Executive Officer, and the other members of the Executive Committee.

Company means Canadian Utilities Limited and, unless the context otherwise requires, includes its subsidiaries and joint arrangements.

DRIP means the dividend reinvestment plan (refer to the "Dividend Reinvestment Plan" section of this MD&A).

Earnings means Adjusted Earnings as defined in the Non-GAAP and Additional GAAP Measures section of this MD&A.

GAAP means Canadian generally accepted accounting principles.

Gigajoule (GJ) is a unit of energy equal to approximately 948.2 thousand British thermal units.

IFRS means International Financial Reporting Standards.

LNG means liquefied natural gas.

Megawatt (MW) is a measure of electric power equal to 1,000,000 watts.

Megawatt hour (MWh) is a measure of electricity consumption equal to the use of 1,000,000 watts of electricity over a one-hour period.

PPA means Power Purchase Arrangements that became effective on January 1, 2001, as part of the process of restructuring the electricity utility business in Alberta. PPAs are legislatively mandated and approved by the AUC.

Regulated Utilities means Electricity Distribution (ATCO Electric Distribution), Electricity Transmission (ATCO Electric Transmission), Natural Gas Distribution (ATCO Gas), Natural Gas Transmission (ATCO Pipelines) and International Natural Gas Distribution (ATCO Gas Australia).

Spark spread is the difference between the selling price of electricity and the marginal cost of producing electricity from natural gas. In this MD&A, spark spreads are based on an approximate industry heat rate of 7.5 GJ per MWh.

CANADIAN UTILITIES LIMITED

INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

FOR THE SIX MONTHS ENDED JUNE 30, 2019

TABLE OF CONTENTS

CONSOLIDATED STATEMENTS OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Three Months Ended June 30 2019	Three Months Ended June 30 2018	Six Months Ended June 30 2019	Six Months Ended June 30 2018
Revenues	5	**902**	967	**2,091**	2,352
Costs and expenses					
Salaries, wages and benefits		**(92)**	(139)	**(180)**	(241)
Energy transmission and transportation		**(51)**	(46)	**(103)**	(90)
Plant and equipment maintenance		**(71)**	(64)	**(131)**	(117)
Fuel costs		**(45)**	(48)	**(123)**	(110)
Purchased power		**(49)**	(43)	**(113)**	(81)
Service concession arrangement costs		**(8)**	(148)	**(103)**	(516)
Depreciation and amortization	8, 9	**(154)**	(182)	**(311)**	(333)
Franchise fees		**(55)**	(44)	**(129)**	(123)
Property and other taxes		**(39)**	(48)	**(87)**	(92)
Unrealized (losses) gains on mark-to-market forward commodity contracts		**(7)**	16	**1**	(8)
Other		**(95)**	(108)	**(168)**	(178)
		(666)	(854)	**(1,447)**	(1,889)
Earnings from investment in joint ventures		**4**	4	**12**	12
Operating profit		**240**	117	**656**	475
Interest income		**5**	9	**11**	18
Interest expense		**(122)**	(124)	**(245)**	(247)
Net finance costs		**(117)**	(115)	**(234)**	(229)
Earnings before income taxes		**123**	2	**422**	246
Income tax recovery (expense)	6	**177**	(4)	**97**	(67)
Earnings (loss) for the period		**300**	(2)	**519**	179
Earnings (loss) attributable to:					
Equity owners of the Company		**299**	(3)	**516**	176
Non-controlling interests		**1**	1	**3**	3
		300	(2)	**519**	179
Earnings (loss) per Class A and Class B share	7	**$1.03**	$(0.07)	**$1.76**	$0.53
Diluted earnings (loss) per Class A and Class B share	7	**$1.03**	$(0.07)	**$1.76**	$0.53

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Three Months Ended June 30 2019	Three Months Ended June 30 2018	Six Months Ended June 30 2019	Six Months Ended June 30 2018
Earnings (loss) for the period	**300**	(2)	**519**	179
Other comprehensive (loss) income, net of income taxes				
Items that will not be reclassified to earnings:				
Re-measurement of retirement benefits (1)	**(38)**	44	**(115)**	23
Items that are or may be reclassified subsequently to earnings:				
Cash flow hedges (2) (5)	**(2)**	1	**(5)**	(4)
Cash flow hedges reclassified to earnings (3) (6)	**2**	3	**4**	3
Foreign currency translation adjustment (4)	**(21)**	(17)	**(25)**	1
	(21)	(13)	**(26)**	–
Other comprehensive (loss) income	**(59)**	31	**(141)**	23
Comprehensive income for the period	**241**	29	**378**	202
Comprehensive income attributable to:				
Equity owners of the Company	**240**	28	**375**	199
Non-controlling interests	**1**	1	**3**	3
	241	29	**378**	202

(1) *Net of income taxes of $7 and $35 million for the three and six months ended June 30, 2019 (2018 - $(17) million and $(9) million).*

(2) *Net of income taxes of $1 and $2 million for the three and six months ended June 30, 2019 (2018 - $(2) million and nil).*

(3) *Net of income taxes of $(1) and $(1) million for the three and six months ended June 30, 2019 (2018 - $(1) and $(1) million).*

(4) *Net of income taxes of nil.*

(5) *$(3) million and $(4) million for the three and six months ended June 30, 2019 relate to cash flow hedges included in liabilities of disposal groups classified as held for sale.*

(6) *$3 million and $4 million for the three and six months ended June 30, 2019 relate to cash flow hedges included in liabilities of disposal groups classified as held for sale.*

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

(millions of Canadian Dollars)	Note	June 30 2019	December 31 2018
ASSETS			
Current assets			
Cash and cash equivalents	15, 17	**464**	599
Accounts receivable and contract assets		**489**	676
Finance lease receivables		**8**	15
Inventories		**37**	31
Restricted project funds	17	**–**	339
Receivable under service concession arrangement	17	**–**	67
Prepaid expenses and other current assets		**52**	129
		1,050	1,856
Assets of disposal groups classified as held for sale	17	**2,836**	–
		3,886	1,856
Non-current assets			
Property, plant and equipment	8, 17	**16,876**	17,259
Intangibles	17	**613**	630
Right-of-use assets	3, 9	**60**	–
Investment in joint ventures	17	**145**	195
Finance lease receivables		**173**	380
Deferred income tax assets	6	**46**	69
Receivable under service concession arrangement	17	**–**	1,329
Other assets		**71**	101
Total assets		**21,870**	21,819
LIABILITIES			
Current liabilities			
Bank indebtedness	15	**4**	–
Accounts payable and accrued liabilities		**394**	845
Lease liabilities	3, 12	**11**	–
Other current liabilities		**20**	120
Short-term debt	10	**550**	175
Long-term debt	11	**361**	485
Non-recourse long-term debt	17	**–**	20
		1,340	1,645
Liabilities of disposal groups classified as held for sale	17	**2,044**	–
		3,384	1,645
Non-current liabilities			
Deferred income tax liabilities	6	**1,147**	1,380
Retirement benefit obligations		**508**	356
Customer contributions	17	**1,692**	1,798
Lease liabilities	3, 12	**51**	–
Other liabilities	17	**86**	278
Long-term debt	11	**8,327**	8,419
Non-recourse long-term debt	17	**–**	1,381
Total liabilities		**15,195**	15,257
EQUITY			
Equity preferred shares		**1,483**	1,483
Class A and Class B share owners' equity			
Class A and Class B shares	14	**1,228**	1,226
Contributed surplus		**15**	15
Retained earnings		**3,812**	3,675
Accumulated other comprehensive loss		**(50)**	(24)
Total equity attributable to equity owners of the Company		**6,488**	6,375
Non-controlling interests		**187**	187
Total equity		**6,675**	6,562
Total liabilities and equity		**21,870**	21,819

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(millions of Canadian Dollars)	Note	Attributable to Equity Owners of the Company							
		Class A and Class B Shares	Equity Preferred Shares	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Loss	Total	Non-Controlling Interests	Total Equity
December 31, 2017		1,162	1,483	12	3,541	(45)	6,153	187	6,340
Earnings for the period		–	–	–	176	–	176	3	179
Other comprehensive income		–	–	–	–	23	23	–	23
Gains on retirement benefits transferred to retained earnings		–	–	–	23	(23)	–	–	–
Shares issued		31	–	–	–	–	31	–	31
Dividends	13, 14	–	–	–	(247)	–	(247)	(3)	(250)
Share-based compensation		1	–	1	–	–	2	–	2
June 30, 2018		1,194	1,483	13	3,493	(45)	6,138	187	6,325
December 31, 2018		1,226	1,483	15	3,675	(24)	6,375	187	6,562
Earnings for the period		–	–	–	**516**	–	**516**	**3**	**519**
Other comprehensive loss		–	–	–	–	**(141)**	**(141)**	–	**(141)**
Losses on retirement benefits transferred to retained earnings		–	–	–	**(115)**	**115**	–	–	–
Dividends	13, 14	–	–	–	**(264)**	–	**(264)**	**(3)**	**(267)**
Share-based compensation		**2**	–	–	–	–	**2**	–	**2**
June 30, 2019		**1,228**	**1,483**	**15**	**3,812**	**(50)**	**6,488**	**187**	**6,675**

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three Months Ended June 30		Six Months Ended June 30	
(millions of Canadian Dollars)	**Note**	**2019**	**2018**	**2019**	**2018**
Operating activities					
Earnings (loss) for the period		**300**	(2)	**519**	179
Adjustments to reconcile earnings to cash flows from operating activities	15	**90**	298	**422**	642
Changes in non-cash working capital		**(76)**	(52)	**(186)**	111
Change in receivable under service concession arrangement		**(13)**	(181)	**(139)**	(580)
Cash flows from operating activities		**301**	63	**616**	352
Investing activities					
Additions to property, plant and equipment		**(220)**	(266)	**(421)**	(506)
Proceeds on disposal of property, plant and equipment		**–**	1	**–**	1
Additions to intangibles		**(16)**	(20)	**(30)**	(34)
Acquisition, net of cash acquired		**–**	–	**–**	(70)
Investment in joint ventures		**–**	–	**–**	(6)
Changes in non-cash working capital		**(20)**	(55)	**(34)**	(81)
Other		**12**	(1)	**12**	(4)
Cash flows used in investing activities		**(244)**	(341)	**(473)**	(700)
Financing activities					
Net issue (repayment) of short-term debt	10	**150**	(50)	**375**	50
Issue of long-term debt		**–**	–	**–**	40
Release of restricted project funds		**72**	277	**177**	493
Repayment of long-term debt		**(3)**	(46)	**(183)**	(46)
Repayment of non-recourse long-term debt		**(4)**	(3)	**(7)**	(7)
Repayment of lease liabilities	12	**(3)**	–	**(6)**	–
Issue of Class A shares		**–**	–	**–**	1
Dividends paid on equity preferred shares		**(16)**	(16)	**(33)**	(33)
Dividends paid to non-controlling interests		**(1)**	(1)	**(3)**	(3)
Dividends paid to Class A and Class B share owners		**(116)**	(93)	**(231)**	(183)
Interest paid		**(138)**	(136)	**(242)**	(238)
Other		**3**	2	**17**	4
Cash flows (used in) from financing activities		**(56)**	(66)	**(136)**	78
Increase (decrease) in cash position (1)		**1**	(344)	**7**	(270)
Foreign currency translation		**(3)**	(2)	**(5)**	(4)
Beginning of period		**603**	490	**599**	418
End of period	15	**601**	144	**601**	144
Presented on balance sheet as follows:					
Cash and cash equivalents		**464**	–	**464**	–
Assets of disposal groups classified as held for sale	17	**141**	–	**141**	–
Bank indebtedness		**(4)**	–	**(4)**	–
		601	–	**601**	–

(1) Cash position includes $45 million which is not available for general use by the Company (2018 - $48 million).

See accompanying Notes to Unaudited Interim Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

JUNE 30, 2019

(Tabular amounts in millions of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 4th Floor, West Building, 5302 Forand Street SW, Calgary, Alberta T3E 8B4 and its registered office is 20th Floor, 10035 - 105 Street, Edmonton, Alberta T5J 2V6. The Company is controlled by ATCO Ltd. and its controlling share owner, the Southern family.

Canadian Utilities Limited is engaged in the following global business activities:

- Electricity (electricity generation, distributed generation, and electricity distribution, transmission and infrastructure development);
- Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, energy storage, and industrial water solutions); and
- Retail Energy (included in the Corporate & Other segment).

The unaudited interim consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (the Company). The statements also include the accounts of a proportionate share of the Company's investments in joint operations and its equity-accounted investments in joint ventures.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The unaudited interim consolidated financial statements are prepared according to International Accounting Standard (IAS) 34 Interim Financial Reporting using accounting policies consistent with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board and IFRS Interpretations Committee (IFRIC). They do not include all the disclosures required in annual consolidated financial statements and should be read in conjunction with the Company's consolidated financial statements for the year ended December 31, 2018, prepared according to IFRS.

The unaudited interim consolidated financial statements are prepared following the same accounting policies used in the Company's most recent annual consolidated financial statements, except for the change in accounting policy described in Note 3 and income taxes. In interim periods, income taxes are accrued using an estimate of the annualized effective tax rate applied to year-to-date earnings.

The unaudited interim consolidated financial statements were authorized for issue by the Audit & Risk Committee, on behalf of the Board of Directors, on July 24, 2019.

BASIS OF MEASUREMENT

The unaudited interim consolidated financial statements are prepared on a historic cost basis, except for derivative financial instruments, retirement benefit obligations and cash-settled share-based compensation liabilities which are carried at remeasured amounts or fair value.

Revenues, earnings and adjusted earnings for any quarter are not necessarily indicative of operations on an annual basis. Quarterly financial results may be affected by the seasonal nature of the Company's operations, changes in electricity prices in Alberta, the timing and demand of natural gas storage capacity sold, changes in natural gas storage fees, the timing of maintenance outages at power generating plants, and the timing of utility rate decisions.

Certain comparative figures have been reclassified to conform to the current presentation.

3. CHANGE IN ACCOUNTING POLICY

LEASES

The Company adopted IFRS 16 *Leases* on January 1, 2019, which introduces a new approach to lease accounting. The Company adopted the standard using the modified retrospective approach, which does not require restatement of prior period financial information, as it recognizes the cumulative impact on the opening balance sheet and applies the standard prospectively. Accordingly, the comparative information in these unaudited interim consolidated financial statements is not restated.

At the inception of a contract, the Company assesses whether the contract is, or contains, a lease based on whether the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. This policy is applied to contracts entered into, or modified, on or after January 1, 2019.

Practical expedients

Effective January 1, 2019, the IFRS 16 transition date, the Company elected to use the following practical expedients under the modified retrospective transition approach:

- Leases with lease terms of less than twelve months (short-term leases) and leases of low-value assets (less than $5,000 U.S. dollars) (low-value leases) that have been identified at transition, were not recognized in the consolidated balance sheet;
- Right-of-use assets on transition were measured at the amount equal to the lease liabilities at transition, adjusted by the amount of any prepaid or accrued lease payments;
- For certain leases having associated initial direct costs, the Company, at initial measurement on transition, excluded these directs costs from the measurement of the right-of-use assets; and
- Any provision for onerous lease contracts previously recognized at the date of adoption of IFRS 16, has been applied to the associated right-of-use asset recognized upon transition.

The Company as a lessee

Where the Company is a lessee, a right-of-use asset representing the right to use the underlying asset with a corresponding lease liability is recognized when the leased asset becomes available for use by the Company.

The right-of-use asset is recognized at cost and is depreciated on a straight-line basis over the shorter of the estimated useful life of the asset and the lease term on a straight-line basis. The cost of the right-of-use asset is based on the following:

- the amount of initial recognition of related lease liability;
- adjusted by any lease payments made on or before inception of the lease;
- increased by any initial direct costs incurred; and
- decreased by lease incentives received and any costs to dismantle the leased asset.

The lease term includes consideration of an option to extend or to terminate if the Company is reasonably certain to exercise that option. In addition, the right-of-use asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

Lease liabilities are initially recognized at the present value of the lease payments. The lease payments are discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. Subsequent to recognition, lease liabilities are measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured when there is a change in future lease payments arising mainly from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, renewal or termination option.

The payments related to short-term leases and low-value leases are recognized as other expenses over the lease term in the unaudited interim consolidated statements of earnings.

Significant accounting estimates and assumptions

In the situation where the implicit interest rate in the lease is not readily determined, the Company uses judgment to estimate the incremental borrowing rate for discounting the lease payments. The Company's incremental borrowing rate generally reflects the interest rate that the Company would have to pay to borrow a similar amount at a similar term and with a similar security. The Company estimates the lease term by considering the facts and circumstances that create an economic incentive to exercise an extension or termination option. Certain qualitative and quantitative assumptions are used when evaluating these incentives.

The Company as a lessor

The Company's unaudited interim consolidated financial statements were not impacted by the adoption of IFRS 16 *Leases* in relation to lessor accounting. Lessors will continue with the dual classification model for recognized leases with the resultant accounting remaining unchanged from IAS 17 *Leases*.

Sub-surface Rights

In June 2019, the IFRS Interpretations Committee, acting on a request for interpretation, concluded that a pipeline sub-surface arrangement is, or contains, a lease under IFRS 16. A pipeline sub-surface arrangement is an agreement with a landowner to lay an underground pipeline in exchange for consideration. It contains a lease because the underground space is physically distinct from the landowner's land, and the owner of the pipeline has exclusive use of the underground space.

The Company is currently assessing the impact of the interpretation on its pipeline sub-surface arrangements. The assessment is expected to be complete before the end of 2019. Based on the preliminary analysis performed to date, the impact on the consolidated financial statements is not expected to be significant.

IMPACT OF CHANGES IN ACCOUNTING POLICY

Impact of adoption of IFRS 16 on unaudited interim consolidated financial statements

On January 1, 2019, the Company recognized $67 million of right-of-use assets and $67 million of lease liabilities. The Company applied its weighted average incremental borrowing rate at January 1, 2019, 3.00 per cent, to determine the amount of lease liabilities. The effect of the adjustment to the amounts recognized in the Company's unaudited interim consolidated balance sheet at January 1, 2019 is shown below.

(millions of Canadian Dollars)	Note	December 31, 2018, as previously reported	IFRS 16 re-measurement adjustments on January 1, 2019	Restated
ASSETS				
Non-current assets				
Right-of-use assets	9	–	67	67
Total assets		21,819	67	21,886
LIABILITIES				
Current liabilities				
Lease liabilities	12	–	11	11
Non-current liabilities				
Lease liabilities	12	–	56	56
Total liabilities		15,257	67	15,324
EQUITY				
Equity preferred shares		1,483	–	1,483
Class A and Class B share owners' equity				
Class A and Class B shares		1,226	–	1,226
Contributed surplus		15	–	15
Retained earnings		3,675	–	3,675
Accumulated other comprehensive loss		(24)	–	(24)
Total equity attributable to equity owners of the Company		6,375	–	6,375
Non-controlling interests		187	–	187
Total equity		6,562	–	6,562
Total liabilities and equity		21,819	67	21,886

The reconciliation of differences between the operating lease commitments disclosed at December 31, 2018 (when applying IAS 17 *Leases*), discounted using the weighted average incremental borrowing rate at January 1, 2019, and the lease liabilities recognized upon adoption of IFRS 16 *Leases*, is shown below.

Operating lease commitments at December 31, 2018, as previously reported	138
Adjustment to reflect discounting of the operating lease commitments at December 31, 2018, using the weighted average incremental borrowing rate	(17)
Lease liabilities at January 1, 2019, before exemptions and other adjustments	121
Exemptions applied upon recognition of lease liabilities:	
Short-term leases	(1)
Contracts not meeting the definition of a lease [(1)]	(55)
Recognition of the lease term extension option [(2)]	2
Lease liabilities recognized at January 1, 2019	67

(1) Contracts not meeting the definition of a lease are comprised of contracts or certain components of contracts that are considered executory service arrangements.

(2) Recognition of the lease term extension option relates to leases where the extension option is reasonably certain to be exercised.

4. SEGMENTED INFORMATION

SEGMENTED RESULTS

Results by operating segment for the three months ended June 30 are shown below.

2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Intersegment Eliminations**	**Consolidated**
Revenues - external	**517**	**346**	**39**	**–**	**902**
	635	304	28	–	967
Revenues - intersegment	**(1)**	**9**	**10**	**(18)**	**–**
	(1)	11	9	(19)	–
Revenues	**516**	**355**	**49**	**(18)**	**902**
	634	315	37	(19)	967
Operating expenses [(1)]	**(263)**	**(214)**	**(55)**	**20**	**(512)**
	(411)	(224)	(54)	17	(672)
Depreciation and amortization	**(89)**	**(63)**	**(4)**	**2**	**(154)**
	(109)	(73)	(2)	2	(182)
Earnings from investment in joint ventures	**1**	**3**	**–**	**–**	**4**
	2	2	–	–	4
Net finance costs	**(80)**	**(38)**	**1**	**–**	**(117)**
	(80)	(39)	4	–	(115)
Earnings (loss) before income taxes	**85**	**43**	**(9)**	**4**	**123**
	36	(19)	(15)	–	2
Income tax recovery (expense)	**123**	**62**	**(1)**	**(7)**	**177**
	(11)	1	5	1	(4)
Earnings (loss) for the period	**208**	**105**	**(10)**	**(3)**	**300**
	25	(18)	(10)	1	(2)
Adjusted earnings (loss)	**106**	**42**	**(24)**	**2**	**126**
	100	27	(20)	–	107
Capital expenditures [(3)]	**108**	**131**	**1**	**–**	**240**
	126	162	3	–	291

Results by operating segment for the six months ended June 30 are shown below.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**1,198**	**794**	**99**	**–**	**2,091**
	1,523	772	57	–	2,352
Revenues - intersegment	**8**	**38**	**19**	**(65)**	**–**
	10	28	19	(57)	–
Revenues	**1,206**	**832**	**118**	**(65)**	**2,091**
	1,533	800	76	(57)	2,352
Operating expenses [1]	**(621)**	**(461)**	**(120)**	**66**	**(1,136)**
	(1,053)	(460)	(99)	56	(1,556)
Depreciation and amortization	**(181)**	**(126)**	**(8)**	**4**	**(311)**
	(201)	(132)	(4)	4	(333)
Earnings from investment in joint ventures	**6**	**6**	**–**	**–**	**12**
	9	3	–	–	12
Net finance costs	**(160)**	**(77)**	**3**	**–**	**(234)**
	(159)	(77)	8	(1)	(229)
Earnings (loss) before income taxes	**250**	**174**	**(7)**	**5**	**422**
	129	134	(19)	2	246
Income tax recovery (expense)	**79**	**27**	**(2)**	**(7)**	**97**
	(36)	(39)	8	–	(67)
Earnings (loss) for the period	**329**	**201**	**(9)**	**(2)**	**519**
	93	95	(11)	2	179
Adjusted earnings (loss)	**222**	**140**	**(38)**	**2**	**326**
	197	128	(37)	–	288
Total assets [2]	**13,405**	**7,799**	**1,196**	**(530)**	**21,870**
	13,494	7,842	574	(91)	21,819
Capital expenditures [3]	**220**	**238**	**2**	**–**	**460**
	242	301	7	–	550

(1) Includes total costs and expenses, excluding depreciation and amortization expense.
(2) 2018 comparatives are at December 31, 2018.
(3) Includes additions to property, plant and equipment and intangibles and $4 million and $9 million of interest capitalized during construction for the three and six months ended June 30, 2019 (2018 - $5 million and $10 million).

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for:

- the timing of revenues and expenses for rate-regulated activities,
- dividends on equity preferred shares of the Company,
- one-time gains and losses,
- unrealized gains and losses on mark-to-market forward commodity contracts,
- significant impairments, and
- items that are not in the normal course of business or a result of day-to-day operations.

Adjusted earnings are a key measure of segment earnings used by the Chief Operating Decision Maker (CODM) to assess segment performance and allocate resources. Other accounts in the unaudited interim consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the three months ended June 30 is shown below.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings (loss)	**106**	**42**	**(24)**	**2**	**126**
	100	27	(20)	–	107
Transaction costs	**(8)**	**–**	**–**	**–**	**(8)**
	–	–	–	–	–
Restructuring and other costs	**–**	**–**	**–**	**–**	**–**
	(36)	(19)	(5)	–	(60)
Unrealized (losses) gains on mark-to-market forward commodity contracts	**(5)**	**–**	**–**	**–**	**(5)**
	12	–	–	–	12
Rate-regulated activities	**120**	**68**	**–**	**(4)**	**184**
	(53)	(22)	–	1	(74)
IT Common Matters decision	**(7)**	**(7)**	**–**	**–**	**(14)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**1**	**1**	**14**	**–**	**16**
	1	–	15	–	16
Other	**–**	**–**	**–**	**–**	**–**
	–	(4)	–	–	(4)
Earnings (loss) attributable to equity owners of the Company	**207**	**104**	**(10)**	**(2)**	**299**
	24	(18)	(10)	1	(3)
Earnings attributable to non-controlling interests					**1**
					1
Earnings (loss) for the period					**300**
					(2)

The reconciliation of adjusted earnings and earnings for the six months ended June 30 is shown below.

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings (loss)	**222**	**140**	**(38)**	**2**	**326**
	197	128	(37)	–	288
Transaction costs	**(8)**	**–**	**–**	**–**	**(8)**
	–	–	–	–	–
Restructuring and other costs	**–**	**–**	**–**	**–**	**–**
	(36)	(19)	(5)	–	(60)
Unrealized gains (losses) on mark-to-market forward commodity forward commodity contracts	**1**	**–**	**–**	**–**	**1**
	(6)	–	–	–	(6)
Rate-regulated activities	**117**	**63**	**–**	**(3)**	**177**
	(66)	(13)	–	2	(77)
IT Common Matters decision	**(7)**	**(7)**	**–**	**–**	**(14)**
	–	–	–	–	–
Dividends on equity preferred shares of Canadian Utilities Limited	**2**	**2**	**29**	**–**	**33**
	2	–	31	–	33
Other	**–**	**1**	**–**	**–**	**1**
	–	(2)	–	–	(2)
Earnings (loss) attributable to equity owners of the Company	**327**	**199**	**(9)**	**(1)**	**516**
	91	94	(11)	2	176
Earnings attributable to non-controlling interests					**3**
					3
Earnings for the period					**519**
					179

Transaction costs

In the second quarter of 2019, the Company incurred transactions costs for the announced sales of the Canadian fossil fuel-based electricity generation portfolio and Alberta Powerline Limited Partnership (see Note 17). As these costs are related to a one-time transaction, they are excluded from adjusted earnings.

Restructuring and other costs

In the second quarter of 2018, the Company recorded restructuring and other costs of $60 million, after tax, that were not in the normal course of business. These costs mainly related to staff reductions and associated severance costs, as well as costs related to decisions to discontinue certain projects that no longer represented long-term strategic value to the Company.

Unrealized gains and losses on mark-to-market forward commodity contracts

The Company enters into forward contracts in order to optimize available merchant capacity and manage exposure to electricity market price movements for its Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. The forward contracts are measured at fair value. Unrealized gains and losses due to changes in the fair value of the forward contracts are recognized in earnings where hedge accounting is not applied. The CODM believes that removal of the unrealized gains or losses on mark-to-market forward commodity contracts provides a better representation of operating results for the Company's Independent Power and Thermal Plants not governed by a Power Purchase Arrangement. Realized gains or losses are recognized in adjusted earnings when the commodity contracts are settled.

Rate-regulated activities

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to as Utilities.

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. In the absence of this guidance, the Utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the Utilities recognize revenues in earnings when amounts are billed to customers, consistent with the regulator-approved rate design. Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles to account for rate-regulated activities in its internal reporting provided to the CODM. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of its segmented disclosures on this basis. Rate-regulated accounting (RRA) standards impact the timing of how certain revenues and expenses are recognized when compared to non-rate regulated activities, to appropriately reflect the economic impact of a regulator's decisions on revenues.

Rate-regulated accounting differs from IFRS in the following ways:

	Timing Adjustment	Items	RRA Treatment	IFRS Treatment
1.	Additional revenues billed in current period	Future removal and site restoration costs, and impact of colder temperatures.	The Company defers the recognition of cash received in advance of future expenditures.	The Company recognizes revenues when amounts are billed to customers and costs when they are incurred.
2.	Revenues to be billed in future periods	Deferred income taxes, impact of warmer temperatures, and impact of inflation on rate base.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company recognizes costs when they are incurred, but does not recognize their recovery until customer rates are changed and amounts are collected through future billings.
3.	Regulatory decisions received	Regulatory decisions received which relate to current and prior periods.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company does not recognize earnings from a regulatory decision when it is received as regulatory assets and liabilities are not recorded under IFRS.
4.	Settlement of regulatory decisions and other items	Settlement of amounts receivable or payable to customers and other items.	The Company recognizes the amount receivable or payable to customers as a reduction in its regulatory assets and liabilities when collected or refunded through future billings.	The Company recognizes earnings when customer rates are changed and amounts are recovered or refunded to customers through future billings.

The significant timing adjustments as a result of the differences between rate-regulated accounting and IFRS are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2019	**2018**	**2019**	**2018**
Additional revenues billed in current period				
Future removal and site restoration costs [1]	**16**	20	**36**	39
Impact of colder temperatures [2]	**–**	–	**12**	12
Revenues to be billed in future periods				
Deferred income taxes [3]	**(28)**	(26)	**(56)**	(59)
Deferred income taxes due to decrease in provincial corporate income tax [4]	**203**	–	**203**	–
Impact of inflation on rate base [5]	**(4)**	–	**(4)**	–
Regulatory decisions received (see below)	**(3)**	–	**(3)**	–
Settlement of regulatory decisions and other items [6]	**–**	(68)	**(11)**	(69)
	184	(74)	**177**	(77)

(1) Removal and site restoration costs are billed to customers over the estimated useful life of the related assets based on forecast costs to be incurred in future periods.

(2) ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Revenues above or below the normal in the current period are refunded to or recovered from customers in future periods.

(3) Income taxes are billed to customers when paid by the Company.

(4) In the second quarter of 2019, the Government of Alberta enacted a phased decrease in the provincial corporate income tax rate from 12 per cent to 8 per cent. This decrease is being phased in increments from July 1, 2019 to January 1, 2022 (see Note 6). As a result of this change, the Alberta Utilities decreased deferred income taxes and increased earnings for the three and six months ended June 30, 2019 by $203 million.

(5) The inflation-indexed portion of ATCO Gas Australia's rate base is billed to customers through the recovery of depreciation in subsequent periods based on the actual rate of inflation. Under rate-regulated accounting, revenue is recognized in the current period for the inflation component of rate base when it is earned. Differences between the amounts earned and the amounts billed to customers are deferred and recognized in revenues over the service life of the related assets.

(6) In the second quarter of 2018, ATCO Electric recorded a decrease in earnings for the period of $38 million mainly related to the refund of deferral account balances for 2013 and 2014. ATCO Gas also recorded a reduction in earnings for the period of $23 million related to the refund of previously over collected transmission costs.

Regulatory decisions received

Under rate-regulated accounting, the Company recognizes earnings from a regulatory decision pertaining to current and prior periods when the decision is received. A description of the significant regulatory decisions recognized in adjusted earnings in 2019 is provided below.

	Decision	Amount	Description
1.	Information Technology (IT) Common Matters	14	In August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. In 2015, the AUC commenced an Information Technology Common Matters proceeding to review the recovery of IT costs by the Alberta Utilities from January 1, 2015 going forward. On June 5, 2019, the AUC issued its decision regarding the IT Common Matters proceeding and directed the Alberta Utilities to reduce the first-year of the Wipro MSA by 13% and to apply a glide path that reduces pricing by 4.61% in each of years 2 through 10. The reduction in adjusted earnings resulting from the decision for the period January 1, 2015 to June 30, 2019 of $14 million was recorded in the second quarter of 2019.
2.	ATCO Electric Transmission General Tariff Application (GTA)	(17)	In June 2017, ATCO Electric Transmission filed a GTA for its operations for 2018 and 2019. The decision was received in July 2019 approving the majority of capital expenditures and operating costs requested. The increase in adjusted earnings resulting from the decision of $17 million was recorded in the second quarter of 2019.

IT Common Matters decision

As described in the IT Common Matters decision above, in August 2014, the Company sold its IT services business to Wipro Ltd. (Wipro) and signed a ten-year IT Master Services Agreement (MSA) effective January 1, 2015. Proceeds of the sale were $204 million, resulting in a one-time after-tax gain of $138 million. In 2014, the Company did not include this gain on sale in adjusted earnings because it was a significant one-time event.

In June 2019, the AUC issued its decision regarding the IT Common Matters proceeding which is described in the regulatory decisions received section above. In the proceeding, the Company presented a considerable amount of evidence, including expert benchmarking and price review studies, to support that the Wipro MSA rates were at fair market value. As such, there was no cross subsidization between the sale price of the Company's IT services business to Wipro in the 2014 transaction and the establishment of IT rates under the MSA. Despite these efforts the AUC found that the Alberta Utilities failed to demonstrate that the IT pricing in the MSA would result in just and reasonable rates.

Consistent with the treatment in 2014, the $14 million reduction booked in the second quarter of 2019, along with future impacts associated with this decision, will not be included in adjusted earnings.

Other

Each quarter, the Company adjusts the deferred tax asset which was recognized as a result of the 2015 Tula Pipeline Project impairment. For the three and six months ended June 30, 2019, the Company recorded a foreign exchange gain of nil and $1 million, respectively (2018 - a foreign exchange loss of $4 million and $2 million) due to a difference between the tax base currency, which is Mexican pesos, and the U.S. dollar functional currency.

5. REVENUES

The Company disaggregates revenues based on the revenue streams and by regulated and non-regulated business operations. The disaggregation of revenues by revenue streams by each operating segment for the three months ended June 30 are shown below:

2019 **2018**	**Electricity**	**Pipelines & Liquids**	**Corporate & Other**	**Total**
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**112**	–	–	**112**
	116	–	–	116
Commodity sales	**4**	**1**	–	**5**
	3	3	–	6
Total sale of goods	**116**	**1**	–	**117**
	119	3	–	122
Rendering of Services				
Distribution services	**129**	**211**	–	**340**
	143	187	–	330
Transmission services	**168**	**73**	–	**241**
	100	65	–	165
Customer contributions	**10**	**4**	–	**14**
	10	5	–	15
Franchise fees	**9**	**46**	–	**55**
	7	38	–	45
Retail electricity and natural gas services	–	–	**30**	**30**
	–	–	27	27
Storage and industrial water	–	**5**	–	**5**
	–	5	–	5
Total rendering of services	**316**	**339**	**30**	**685**
	260	300	27	587
Lease income				
Finance lease	**7**	–	–	**7**
	8	–	–	8
Operating lease	**22**	–	–	**22**
	62	–	–	62
Total lease income	**29**	–	–	**29**
	70	–	–	70
Service concession arrangement	**42**	–	–	**42**
	181	–	–	181
Other	**14**	**6**	**9**	**29**
	5	1	1	7
Total	**517**	**346**	**39**	**902**
	635	304	28	967

The disaggregation of revenues by revenue streams by each operating segment for the six months ended June 30 are shown below:

2019 2018	Electricity	Pipelines & Liquids	Corporate & Other	Total
Revenue Streams				
Sale of Goods				
Electricity generation and delivery	**276**	**–**	**–**	**276**
	200	–	–	200
Commodity sales	**8**	**6**	**–**	**14**
	8	6	–	14
Total sale of goods	**284**	**6**	**–**	**290**
	208	6	–	214
Rendering of Services				
Distribution services	**284**	**505**	**–**	**789**
	283	498	–	781
Transmission services	**337**	**139**	**–**	**476**
	269	129	–	398
Customer contributions	**20**	**9**	**–**	**29**
	19	9	–	28
Franchise fees	**17**	**112**	**–**	**129**
	15	110	–	125
Retail electricity and natural gas services	**–**	**–**	**86**	**86**
	–	–	54	54
Storage and industrial water	**–**	**12**	**–**	**12**
	–	19	–	19
Total rendering of services	**658**	**777**	**86**	**1,521**
	586	765	54	1,405
Lease income				
Finance lease	**16**	**–**	**–**	**16**
	17	–	–	17
Operating lease	**43**	**–**	**–**	**43**
	121	–	–	121
Total lease income	**59**	**–**	**–**	**59**
	138	–	–	138
Service concession arrangement	**168**	**–**	**–**	**168**
	580	–	–	580
Other	**29**	**11**	**13**	**53**
	11	1	3	15
Total	**1,198**	**794**	**99**	**2,091**
	1,523	772	57	2,352

Disaggregation of revenues by rate-regulated and non-rate-regulated business operations is shown below:

	Three Months Ended June 30		Six Months Ended June 30	
	2019	**2018**	**2019**	**2018**
Rate-regulated business operations				
Rate-regulated Electricity				
Electricity Distribution	**151**	158	**330**	314
Electricity Transmission	**175**	103	**350**	274
	326	261	**680**	588
Rate-regulated Pipelines & liquids				
Natural Gas Distribution	**218**	182	**556**	532
Natural Gas Transmission	**75**	66	**143**	132
International Natural Gas Distribution	**39**	44	**74**	82
	332	292	**773**	746
Total rate-regulated business operations	**658**	553	**1,453**	1,334
Non-rate-regulated business operations				
Non-rate-regulated Electricity				
Independent Power Plants	**12**	104	**166**	178
Thermal PPA Plants	**132**	82	**174**	165
International Power Generation	**4**	5	**9**	10
Service concession arrangement	**42**	181	**168**	580
	190	372	**517**	933
Non-rate-regulated Pipelines & liquids				
Storage and Industrial Water	**5**	5	**12**	19
	5	5	**12**	19
Other non-rate-regulated business operations				
Retail Electricity and Natural Gas Services	**30**	27	**86**	54
Other	**19**	10	**23**	12
	49	37	**109**	66
Total non-rate-regulated business operations	**244**	414	**638**	1,018
Total	**902**	967	**2,091**	2,352

6. INCOME TAXES

On May 28, 2019, the Alberta government passed Bill 3, the Job Creation Tax Cut, which will reduce the Alberta provincial corporate tax rate from 12 per cent to 8 per cent in a phased approach between July 1, 2019 and January 1, 2022.

As a result of this change, the Company made an adjustment to current and deferred income taxes of $1 million and $210 million, respectively, which was recorded in the second quarter of 2019.

As the tax rate change came into effect on July 1, 2019, the combined federal and Alberta statutory Canadian income tax rate for 2019 is 26.5 per cent. Prior to the change, the combined federal and Alberta statutory Canadian income tax rate for 2019 was 27.0 per cent.

7. EARNINGS PER SHARE

Earnings per Class A non-voting (Class A) and Class B common (Class B) share are calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share are calculated using the treasury stock method, which reflects the potential exercise of stock options and vesting of shares under the Company's mid-term incentive plan (MTIP) on the weighted average Class A and Class B shares outstanding.

The earnings and average number of shares used to calculate earnings per share are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
	2019	**2018**	**2019**	**2018**
Average shares				
Weighted average shares outstanding	**272,644,055**	271,175,287	**272,619,030**	270,946,405
Effect of dilutive stock options	**63,048**	33,797	**48,967**	38,532
Effect of dilutive MTIP	**508,047**	609,230	**527,926**	583,452
Weighted average dilutive shares outstanding	**273,215,150**	271,818,314	**273,195,923**	271,568,389
Earnings (loss) for earnings per share calculation				
Earnings (loss) for the period	**300**	(2)	**519**	179
Dividends on equity preferred shares of the Company	**(16)**	(16)	**(33)**	(33)
Dividends to non-controlling interests	**(1)**	(1)	**(3)**	(3)
Earnings (loss) attributable to Class A and B shares	**283**	(19)	**483**	143
Earnings (loss) and diluted earnings (loss) per Class A and Class B share				
Earnings (loss) per Class A and Class B share	**$1.03**	$(0.07)	**$1.76**	$0.53
Diluted earnings (loss) per Class A and Class B share	**$1.03**	$(0.07)	**$1.76**	$0.53

8. PROPERTY, PLANT AND EQUIPMENT

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Electricity Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost						
December 31, 2018	19,315	1,950	703	661	1,042	23,671
Additions	**13**	**46**	**1**	**417**	**3**	**480**
Transfers	**362**	**5**	**–**	**(375)**	**8**	**–**
Retirements and disposals	**(21)**	**(27)**	**(2)**	**–**	**(10)**	**(60)**
Reclassification to assets held for sale (*Note 17*)	**–**	**(1,801)**	**(13)**	**(21)**	**(21)**	**(1,856)**
Foreign exchange rate adjustment	**(68)**	**–**	**(2)**	**(6)**	**(2)**	**(78)**
June 30, 2019	**19,601**	**173**	**687**	**676**	**1,020**	**22,157**
Accumulated depreciation						
December 31, 2018	4,384	1,338	163	84	443	6,412
Depreciation	**229**	**24**	**8**	**–**	**22**	**283**
Retirements and disposals	**(21)**	**(18)**	**(2)**	**–**	**(10)**	**(51)**
Reclassification to assets held for sale (*Note 17*)	**–**	**(1,335)**	**–**	**–**	**(13)**	**(1,348)**
Foreign exchange rate adjustment	**(12)**	**–**	**–**	**(3)**	**–**	**(15)**
June 30, 2019	**4,580**	**9**	**169**	**81**	**442**	**5,281**
Net book value						
December 31, 2018	14,931	612	540	577	599	17,259
June 30, 2019	**15,021**	**164**	**518**	**595**	**578**	**16,876**

The additions to property, plant and equipment included $9 million of interest capitalized during construction for the six months ended June 30, 2019 (2018 - $10 million).

9. RIGHT-OF-USE ASSETS

The Company's right-of-use assets mainly relate to the lease of land and buildings.

	Note	Land and Buildings
Cost		
January 1, 2019, on adoption of IFRS 16	3	67
June 30, 2019		**67**
Accumulated depreciation		
January 1, 2019, on adoption of IFRS 16	3	–
Depreciation		**7**
June 30, 2019		**7**
Net book value		
January 1, 2019, on adoption of IFRS 16	3	67
June 30, 2019		**60**

10. SHORT-TERM DEBT

At June 30, 2019, the Company had $550 million of commercial paper outstanding at a weighted average effective interest rate of 1.95 per cent, maturing in July 2019 (December 31, 2018 - $175 million of commercial paper outstanding at a weighted average effective interest rate of 2.25 per cent, matured in January 2019).

The commercial paper is supported by the Company's long-term committed credit facilities.

11. LONG-TERM DEBT

On January 23, 2019, CU Inc., a wholly owned subsidiary of the Company, repaid $180 million of 5.432 per cent debentures.

12. LEASE LIABILITIES

The Company has recognized lease liabilities in relation to the arrangements to lease land and buildings. The reconciliation of movements in lease liabilities is as follows:

	Note	
January 1, 2019, on adoption of IFRS 16	3	67
Interest expense		**1**
Lease payments		**(6)**
		62
Less: amounts due within one year		**(11)**
June 30, 2019		**51**

The maturity analysis of the undiscounted contractual balances of the lease liabilities is as follows:

In one year or less	**13**
In more than one year, but not more than five years	**38**
In more than five years	**20**
	71

During the three and six months ended June 30, 2019, $1 million and $2 million, respectively, was expensed in relation to low-value leases, and no expenses were incurred in relation to short-term leases or leases with variable payments.

13. EQUITY PREFERRED SHARES

Cash dividends declared and paid per share are as follows:

	Three Months Ended June 30		Six Months Ended June 30	
(dollars per share)	2019	2018	2019	2018
Perpetual Cumulative Second Preferred Shares				
4.60% Series V	**0.2875**	0.2875	**0.5750**	0.5750
Cumulative Redeemable Second Preferred Shares				
3.403% Series Y	**0.2127**	0.2127	**0.4254**	0.4254
4.90% Series AA	**0.3063**	0.3063	**0.6125**	0.6125
4.90% Series BB	**0.3063**	0.3063	**0.6125**	0.6125
4.50% Series CC	**0.2813**	0.2813	**0.5625**	0.5625
4.50% Series DD	**0.2813**	0.2813	**0.5625**	0.5625
5.25% Series EE	**0.3281**	0.3281	**0.6563**	0.6563
4.50% Series FF	**0.2813**	0.2813	**0.5625**	0.5625

The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

14. CLASS A AND CLASS B SHARES

At June 30, 2019, there were 199,419,945 (December 31, 2018 - 199,366,495) Class A shares and 73,735,780 (December 31, 2018 - 73,774,980) Class B shares outstanding. In addition, there were 774,900 options to purchase Class A shares outstanding at June 30, 2019, under the Company's stock option plan.

DIVIDENDS

The Company declared and paid cash dividends of $0.4227 and $0.8454 per Class A and Class B share during the three and six months ended June 30, 2019 (2018 - $0.3933 and $0.7866). The Company's policy is to pay dividends quarterly on its Class A and Class B shares. The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

On July 9, 2019, the Company declared a third quarter dividend of $0.4227 per Class A and Class B share.

DIVIDEND REINVESTMENT PROGRAM

No Class A shares were issued under the Company's dividend reinvestment program (DRIP) during the three and six months ended June 30, 2019, as on January 10, 2019, the DRIP was suspended.

During the three and six months ended June 30, 2018, 490,295 and 980,509 Class A shares were issued under the DRIP, using re-invested dividends of $15 million and $31 million. The shares were priced at an average of $30.73 and $31.91 per share, respectively.

15. CASH FLOW INFORMATION

ADJUSTMENTS TO RECONCILE EARNINGS TO CASH FLOWS FROM OPERATING ACTIVITIES

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	Three Months Ended June 30		Six Months Ended June 30	
	2019	**2018**	**2019**	**2018**
Depreciation and amortization	**154**	182	**311**	333
Earnings from investment in joint ventures, net of dividends received	**2**	2	**2**	(1)
Income tax (recovery) expense	**(177)**	4	**(97)**	67
Unearned availability incentives	**6**	1	**6**	(4)
Unrealized losses (gains) on mark-to-market forward commodity contracts	**7**	(16)	**(1)**	8
Contributions by customers for extensions to plant	**10**	25	**35**	48
Amortization of customer contributions	**(14)**	(15)	**(29)**	(28)
Net finance costs	**117**	115	**234**	229
Income taxes paid	**(24)**	(20)	**(56)**	(38)
Other	**9**	20	**17**	28
	90	298	**422**	642

CASH POSITION

Cash position in the consolidated statement of cash flow at June 30 is comprised of:

	2019	**2018**
Cash	**556**	100
Short-term investments	**4**	–
Restricted cash (1)	**45**	48
Cash and cash equivalents (2)	**605**	148
Bank indebtedness	**(4)**	(4)
	601	144

(1) Cash balances which are restricted under the terms of joint arrangement agreements are considered not available for general use by the Company.

(2) Includes $141 million of cash and cash equivalents classified as assets held for sale (see Note 17).

16. FINANCIAL INSTRUMENTS

FAIR VALUE MEASUREMENT

Financial instruments are measured at amortized cost or fair value. Fair value represents the estimated amounts at which financial instruments could be exchanged between knowledgeable and willing parties in an arm's length transaction. Determining fair value requires management judgment. The valuation methods used to determine the fair value of each financial instrument and its associated level in the fair value hierarchy is described below.

Financial Instruments	Fair Value Method
Measured at Amortized Cost	
Cash and cash equivalents, accounts receivable and contract assets, restricted project funds, bank indebtedness, accounts payable and accrued liabilities and short-term debt.	Assumed to approximate carrying value due to their short-term nature.
Finance lease receivables and receivable under service concession arrangement.	Determined using a risk-adjusted interest rate to discount future cash receipts (Level 2).
Long-term debt and non-recourse long-term debt.	Determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements (Level 2).
Measured at Fair Value	
Interest rate swaps	Determined using interest rate yield curves at period-end (Level 2).
Foreign currency contracts	Determined using quoted forward exchange rates at period-end (Level 2).
Commodity contracts	Determined using observable period-end forward curves, with inputs validated by publicly available market providers. The fair values were also determined using extrapolation formulas using readily observable inputs and implied volatility (Level 2).

FINANCIAL INSTRUMENTS MEASURED AT AMORTIZED COST

The fair values of the Company's financial instruments measured at amortized cost are as follows:

	June 30, 2019		December 31, 2018	
Recurring Measurements	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial Assets				
Finance lease receivables	**181**	**242**	395	487
Receivable under service concession arrangement (1)	–	–	1,396	1,396
Financial Liabilities				
Long-term debt	**8,688**	**10,351**	8,904	9,547
Non-recourse long-term debt (1)	–	–	1,401	1,474

(1) Reclassified as assets and liabilities held for sale (Note 17).

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

The Company's derivative instruments are measured at fair value. At June 30, 2019, the following derivative instruments were outstanding:

- interest rate swaps for the purpose of limiting interest rate risk on the variable future cash flows of long-term debt and non-recourse long-term debt held in a joint venture;
- foreign currency forward contracts for the purpose of limiting exposure to exchange rate fluctuations relating to expenditures denominated in Australian dollars and Mexican pesos; and
- natural gas and forward power sale and purchase contracts for the purpose of limiting exposure to electricity and natural gas market price movements.

The balance sheet classification and fair values of the Company's derivative financial instruments are as follows:

	Subject to Hedge Accounting		Not Subject to Hedge Accounting		
Recurring Measurements	**Interest Rate Swaps**	**Commodities**	**Commodities**	**Foreign Currency Forward Contracts**	**Total Fair Value of Derivatives**
June 30, 2019					
Financial Liabilities					
Other current liabilities (1)	**4**	**14**	**21**	**_**	**39**
Other liabilities (1)	**_**	**6**	**14**	**_**	**20**
December 31, 2018					
Financial Assets					
Prepaid expenses and other current assets	1	2	_	_	3
Other assets	1	2	4	_	7
Financial Liabilities					
Other current liabilities	_	15	34	4	53
Other liabilities	3	8	27	_	38

(1) At June 30, 2019, the Company paid a total of $39 million of cash collateral to third parties on commodity forward positions related to future periods (December 31, 2018 - $18 million). The contracts held with these third parties have an enforceable master netting arrangement, which allows the right to offset.

Notional and maturity summary

The notional value and maturity dates of the Company's derivative instruments outstanding are as follows:

	Subject to Hedge Accounting			Not Subject to Hedge Accounting		
Notional value and maturity	**Interest Rate Swaps**	**Natural Gas (1)**	**Power (2)**	**Natural Gas (1)**	**Power (2)**	**Foreign Currency Forward Contracts**
June 30, 2019						
Purchases (3)	–	**8,619,000**		**28,988,000**	**2,237,565**	–
Sales (3)	–	–	**748,640**	**3,039,700**	**5,814,835**	–
Currency						
Canadian dollars	**1**	–	–	–	–	–
Australian dollars	**741**	–	–	–	–	–
Mexican pesos	**570**	–	–	–	–	**100**
Maturity	**2019-2023**	**2019-2021**	**2019-2020**	**2019-2021**	**2019-2021**	**2019**
December 31, 2018						
Purchases (3)	–	12,545,000	–	58,518,200	3,254,650	–
Sales (3)	–	–	1,193,640	7,740,700	7,574,926	–
Currency						
Canadian dollars	2	–	–	–	–	–
Australian dollars	744	–	–	–	–	–
Mexican pesos	570	–	–	–	–	140
British pounds	–	–	–	–	–	74
Maturity	2019-2023	2019-2021	2019-2020	2019-2022	2019-2021	2019

(1) Notional amounts for the natural gas purchase contracts are the maximum volumes that can be purchased over the terms of the contracts.

(2) Notional amounts for the forward power sale and purchase contracts are the commodity volumes committed in the contracts.

(3) Volumes for natural gas and power derivatives are in GJ and MWh, respectively.

17. DISPOSAL GROUPS AND ASSETS CLASSIFIED AS HELD FOR SALE

Canadian fossil fuel-based electricity generation portfolio

On May 27, 2019, the Company announced that it had entered into agreements to sell its entire Canadian fossil fuel-based electricity generation portfolio (Electricity generation disposal group) for the aggregate proceeds of approximately $835 million.

An agreement with Heartland Generation Ltd., an affiliate of Energy Capital Partners, includes 10 partly or fully owned natural gas-fired and coal-fired electricity generation assets located in Alberta, British Columbia, and Ontario.

In two other separate transactions, the Company entered into agreements to sell its 50 per cent ownership interest in the Cory Cogeneration Station to SaskPower International and its 50 per cent ownership interest in Brighton Beach Power to Ontario Power Generation.

The Cory Cogeneration Station transaction closed in July 2019. The remaining sale transactions are expected to close before December 31, 2019, subject to the receipt of regulatory approvals and the satisfaction of other customary closing conditions.

Alberta PowerLine

On June 24, 2019, the Company announced that it had entered into agreements to sell its entire ownership interest in Alberta PowerLine (APL disposal group), a partnership between the Company and Quanta Services Inc. for the aggregate proceeds of approximately $300 million and the assumption of approximately $1.4 billion of debt, excluding deferred financing charges.

The transaction is expected to close before December 31, 2019, subject to the receipt of regulatory approvals and the satisfaction of other customary closing conditions.

Assets and liabilities of disposal groups classified as held for sale

The Company has classified the assets and liabilities of the above-mentioned disposal groups as assets held for sale. These assets and liabilities are reported in the Electricity operating segment.

Assets and liabilities of disposal groups are classified as held for sale if their carrying amount will be recovered principally through a sale transaction. They are measured at the lower of their carrying value and fair value less costs to sell, except for deferred tax assets, assets arising from employee benefits and financial assets and liabilities that are carried at fair value.

Assets held for sale are not depreciated or amortized while they are classified as held for sale. Interest and other expenses attributable to the liabilities of a disposal group classified as held for sale continue to be recognized.

The major classes of assets and liabilities of the disposal groups as at June 30, 2019 are as follows:

		Reclassification of assets and liabilities of disposal groups			
(millions of Canadian Dollars)	**Assets and liabilities before reclassification**	**Electricity generation disposal group**	**APL disposal group**	**Total**	**Assets and liabilities after reclassification**
ASSETS					
Current assets					
Cash and cash equivalents	605	141	–	**141**	464
Accounts receivable and contract assets	561	68	4	**72**	489
Finance lease receivables	19	11	–	**11**	8
Restricted project funds	235	–	235	**235**	–
Receivable under service concession arrangement	109	–	109	**109**	–
Prepaid expenses and other current assets	92	40	–	**40**	52
		260	348	**608**	
Non-current assets					
Property, plant and equipment	17,384	508	–	**508**	16,876
Intangibles	631	18	–	**18**	613
Investment in joint ventures	180	35	–	**35**	145
Finance lease receivables	380	207	–	**207**	173
Deferred income tax assets	58	12	–	**12**	46
Receivable under service concession arrangement	1,425	–	1,425	**1,425**	–
Other assets	94	23	–	**23**	71
Assets of disposal groups classified as held for sale		1,063	1,773	**2,836**	
LIABILITIES					
Current liabilities					
Accounts payable, accrued liabilities and other current liabilities	670	110	146	**256**	414
Non-recourse long-term debt	30	15	15	**30**	–
		125	161	**286**	
Non-current liabilities					
Deferred income tax liabilities	1,214	23	51	**74**	1,140
Customer contributions	1,804	112	–	**112**	1,692
Other liabilities	294	148	60	**208**	86
Non-recourse long-term debt	1,364	45	1,319	**1,364**	–
Liabilities of disposal groups classified as held for sale		453	1,591	**2,044**	
Net assets of disposal groups classified as held for sale		610	182	**792**	